ORIGINAL

0000000830

BEFORE THE ARIZONA CORPORATION COMMISSION RECEIVED

2004 FEB -3 P 3:53

AZ CORP COMMISSION
DOCUMENT CONTROL

Arizona Corporation Commission
DOCKETED
FEB 03 2004
DOCKETED BY

MARC SPITZER
CHAIRMAN
WILLIAM A. MUNDELL
COMMISSIONER
JEFF HATCH-MILLER
COMMISSIONER
MIKE GLEASON
COMMISSIONER
KRISTIN K. MAYES
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

Docket No. E-01345A-03-0437

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimonies of Marylee Diaz Cortez, Stephen G. Hill, William A. Rigsby, Dr. Richard A. Rosen, David A. Schlissel and Dr. John Stutz in the above-referenced matter. Copies of Mr. Schlissel's unredacted testimony will be provided upon request to those parties who have executed a confidentiality agreement.

RESPECTFULLY SUBMITTED this 3rd day of February, 2004.

Scott S. Wakefield
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES
of the foregoing filed this 3rd day
of February, 2004 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/
emailed this 3rd day of February, 2004 to:

Lyn Farmer, Chief Administrative Law Judge*
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007
Lfarmer@cc.state.az.us

Christopher Kempley, Chief Counsel*
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007
Ckempley@cc.state.az.us

Ernest Johnson, Director*
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007
Ejohnson@cc.state.az.us

Thomas L. Mumaw*
Karilee S. Ramaley*
Pinnacle West Capital Corp.
Law Department
PO Box 53999
Phoenix, Arizona 85072
Thomas.mumaw@pinnaclewest.com
Karilee.ramaley@pinnaclewest.com

Jeffrey B. Guldner*
Teresa Voss*
Snell & Wilmer L.L.P.
400 East Van Buren Street
Phoenix, Arizona 85004
jguldner@swlaw.com
tvoss@swlaw.com

C. Webb Crockett
Fennemore Craig
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012
wcrocket@fclaw.com

Major Allen G. Erickson
AFCES A/ULT
139 Barnes Drive
Suite 1
Tyndall AFB, Florida 32403
allen.erickson@tyndall.af.mil

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East 7th Street
Suite 2110
Cincinnati, Ohio 45202
mkurtzlaw@aol.com

Walter W. Meek
AUIA
2100 North Central Avenue
Suite 210
Phoenix, Arizona 85004
meek@auia.org

Nicholas J. Enoch
Lubin & Enoch
349 North 4th Avenue
Phoenix, Arizona 85003
Nicholas.enoch@azbar.org

Bill Murphy
Murphy Consulting
2422 East Palo Verde Drive
Phoenix, Arizona 85016
billmurphy@cox.net

Jay L. Shapiro
Patrick J. Black
Fennemore Craig
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012
jshapiro@fclaw.com
pblack@fclaw.com

Robert W. Geake
Arizona Water Company
P.O. Box 29006
Phoenix, Arizona 85038
bgeake@azwater.com

Andrew W. Bettwy
Bridget A. Branigan
Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, Nevada 89150
andy.bettwy@swgas.com

Timothy M. Hogan
Arizona Center for Law
in the Public Interest
202 East McDowell Road
Suite 153
Phoenix, Arizona 85004
thogan@aclpi.org

Michael A. Curtis
William P. Sullivan
Larry Udall
Martinez & Curtis, P.C.
2712 North 7th Street
Phoenix, Arizona 85006
mcurtis401@aol.com
wsullivan@martinezcurtis.com
ludall@martinezcurtis.com

Raymond S. Heyman
Laura Schoeler
Roshka, Heyman & DeWulf
400 East Van Buren
Suite 800
Phoenix, Arizona 85004
rheyman@rhd-law.com

Deborah R. Scott
UniSource Energy Services
One South Church Street
Suite 200
Tucson, Arizona 85702
dscott@tucsonelectric.com

J. William Moore
Attorney at Law
1144 East Jefferson
Phoenix, Arizona 85034
jwilliammoore@worldnet.att.net

Penny Anderson
Western Resource Advocates
2260 Baseline Road
Suite 200
Boulder, Colorado 80302
penny@westernresources.org

Jana Van Ness*
Arizona Public Service Company
Mail Station 9905
P.O. Box 53999
Phoenix, Arizona 85072-3999
Jana.VanNess@apsc.com

Marvin S. Cohen
Sacks Tierney P.A.
4250 North Drinkwater Blvd.
4th Floor
Scottsdale, Arizona 85251
marvin.cohen@sackstierney.com

Cynthia Zwick
Arizona Community Action Association
2627 North 3rd Street
Suite 2
Phoenix, Arizona 85004
czwick@azcaa.org

S. David Childers
Low & Childers
2999 North 44th Street
Suite 250
Phoenix, Arizona 85018
dchilders@lowchilders.com

James M. Van Nostrand
Katherine A. McDowell
George M. Galloway
Stoel Rives
900 SW 5th Avenue
Suite 2600
Portland, Oregon 97204
jmvannostrand@stoel.com
kamcdowell@stoel.com
gmgalloway@stoel.com

Greg Patterson
Arizona Competitive Power Alliance
916 West Adams
Suite 3
Phoenix, Arizona 85007
gpattersonCPA@aol.com

Rebecca C. Salisbury
56th Fighter Wing JA
7383 North Litchfield Road
Luke AFB, Arizona 85309-1540
Rebecca.Salisbury@luke.af.mil

Jon Poston
AARP Electric Rate Project
6733 East Dale Lane
Cave Creek, Arizona 85331
Jon_Poston@prodigy.net

Coralette Hannon
AARP Department of State Affairs
6705 Reedy Creek Road
Charlotte, North Carolina 28215
channon@aarp.org

Lawrence V. Robertson, Jr.
Munger Chadwick
National Bank Plaza
333 North Wilmot
Suite 300
Tucson, Arizona 85711
lvrobertson@mungerchadwick.com

David Berry
Western Resource Advocates
P.O. Box 1064
Scottsdale, Arizona 85252-1064
azbluhill@aol.com

Jay I. Moyes
Moyes Storey
3003 North Central Avenue
Suite 1250
Phoenix, Arizona 85012
jimoyes@lawms.com

By Jennifer Rumph
Jennifer Rumph

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 3, 2004

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's revenue requirement recommendation for APS based on my own analyses as well as the analyses of other RUCO witnesses.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. I worked closely with RUCO consultants in formulating RUCO's position regarding APS's request to transfer generation assets from an affiliate to APS, and was responsible, along with RUCO witness William Rigsby for reflecting the impact of those positions on APS's revenue requirements.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-7.

SUMMARY OF ISSUES

Q. Please summarize the issues and recommendations you address in your testimony.

A. My testimony addresses the following issues:

* Retail Competition – examination of status of retail competition and recommendation to return APS to regulated monopoly status.
* PWEC Assets – pursuant to RUCO witness Mr. Schlissel's finding to allow the market to determine the economic value of the PWEC energy and capacity, recommend this docket be divided in two phases – Phase I to determine the revenue requirement for all aspects excepting PWEC energy and capacity and Phase II dedicated to APS's generation resource needs.
* PWEC Interest Premium – recommendation to include an on-going annual credit to ratepayers for the 264 basis point premium that APS receives from PWEC.

* 1999 Settlement Agreement – examination of the status of the terms of the agreement and recommendation to nullify the terms of the agreement prospectively.
* Interim Spent Fuel Storage – examination of cost deferrals and on-on-going costs and recommendation for recovery of both deferred and on-going costs, with no return on accrued deferred balance.
* Direct Access Expenses – examination of to-date deferrals and projected on-going costs. Recommendation of recovery of deferred costs, with no on-going costs pursuant to RUCO's recommendation to return to retail rate of return regulation.
* Transmission Assets and Expenses – recommendation that the ACC retain jurisdiction over APS's retail transmission assets and expenses.
* Environmental Portfolio Standard and Demand Side Management Funding – recommendation to redirect revenues collected through the EAASE fund to DSM programs and to allow the EPS surcharge to remain the sole funding source for EPS.
* Future Demand Side Management Programs – recommendation to increase the funding level for DSM programs to achieve a 1% reduction in load growth.

REVENUE REQUIREMENTS

Q. Please summarize your recommended revenue requirements for APS.

A. RUCO recommends that APS's revenue requirement be reduced by at least $53.605 million, or 2.84%. RUCO's recommended revenue requirements are summarized on Schedule MDC-1. RUCO's Original Cost, Fair Value, and Reconstruction Cost New Depreciation rate bases of $3,051,479,000, $4,065,086,000 and $5,078,693,000 respectively are shown on Schedule MDC-2. The detail supporting the rate base is presented on Schedule MDC-3. RUCO's recommended adjusted operating income is presented on Schedule MDC-4. The detail supporting this recommendation is presented on Schedule MDC-5.

RETAIL COMPETITION

Q. What were RUCO's primary concerns in this case?

A. It has been many years since APS's rates have been fully audited and litigated. The fairness and reasonableness of the current rates is called into question given this long lapse of time between rate reviews, as well as the impact of failed regulatory attempts to create a competitive electric market. RUCO's primary concern in this docket is to establish fair and reasonable rates and to recreate a regulatory model that will protect both ratepayers and the Company from the volatile effects of competitive electric markets.

Q. Has the Commission already taken some steps to protect ratepayers from dysfunctional competitive electric environments?

A. Yes. On September 10, 2002 the Commission issued Decision No. 65154 which among other things stayed the generation divestiture requirement of the APS 1999 settlement agreement. Decision No. 65154 effectively rendered APS a vertically integrated utility once again. The Commission attributed its actions in Decision No. 65154 to the failed development of a functional competitive wholesale electric market and the need to protect the public interest. The Commission stated as follows:

> In actuality, no retail competition exists; market power is held by the incumbent utilities; no RTO is in effect; transmission constraints exist that potentially exacerbate market abuse; the GAO has issued a negative report on the FERC's ability to manage competitive markets; both TEP and APS recognize a problem – one wants to postpone its divestiture while the other is affected by its parent's and affiliates' adverse financial considerations; proposed new generation may be cancelled if it is not able to find a market; more protections are needed against self-dealing and inappropriate affiliate transactions; and investigations are ongoing into market manipulations and improprieties. . . .
>
> We find that due to circumstances outside our control or the control of any party, and in order to protect the public interest, we must take further action to regulate the transition to competition. [Decision No. 65154, page 22]

Q. What other steps has the Commission taken?

A. The Commission recognized in Decision No. 65796 that the affiliate created to hold APS's generation assets (Pinnacle West Energy Corporation or PWEC) was rendered unable to raise capital as a direct result of the stay in divestiture. In that decision the Commission authorized APS to issue debt to cover the financing needs of the generation assets held by PWEC.

Q. Did RUCO support the findings in that decision?

A. Yes, as far as those findings went. At that time RUCO advocated for these additional findings:

1) A provision that APS be required to file for ACC approval of a transfer of the PWEC assets to APS;
2) Full investigation of APS's cost of service in the context of a rate case;
3) A review of the PWEC assets regarding economic value and used and usefulness;
4) A comprehensive review of the electric competition rules and the desirability and applicability in today's environment, and
5) The formulation and development of a regulatory framework that will protect ratepayers and the Company from market dysfunction.

These additional findings were not included in Decision No. 65154. However, RUCO believes these issues are just as applicable today as they were a year ago. In fact, probably more so given APS's pending rate case.

Q. What does RUCO believe needs to be accomplished in this case?

A. As with any rate case, there needs to be a determination of cost of service and fair and reasonable rates. More importantly, a new regulatory framework needs to be developed that will protect ratepayers from dysfunctional electric markets, yet allow the Company an opportunity to earn a fair rate of return on its utility assets. The competition rules need to be revised to reflect the new regulatory framework, and the status of the 1999 settlement agreement needs to be resolved in some manner (i.e. renegotiated, litigated through this proceeding, or voided to be consistent with a new regulatory framework and the lack of functional retail electric markets).

Q. Why is it important that these issues be resolved in this docket?

A. As I have testified to in many previous APS dockets, a functional retail electric market has failed to develop as envisioned. The Commission has recognized this, and via Decision No. 65154, has modified the intended course of retail competition. RUCO supports the Commission decision to modify the course of retail electric competition. However, RUCO also recognizes that Decision No. 65154 has left a number of unresolved issues or "loose ends". These loose ends include the status of the provisions in the 1999 settlement agreement, the electric competition rules, and the future shape of retail electric regulation. These loose ends are a detriment both to ratepayers and the electric utilities and put both in the unenviable situation of not knowing the rules of the game. For the best interests of all parties, new rules need to be clearly defined as a product of this docket.

Q. What is required in this docket?

A. First, to recognize the experiment into retail competition has failed. This is evident from the California experience and how that situation affected local power costs. Second, to recognize that no retail market has developed, and ratepayers have not chosen to seek direct access electric power. Third, to rebuild a retail regulatory framework, and abandon the failed specter of a competitive retail market.

Q. Why isn't this recommendation inconsistent with RUCO's position at the time of the 1999 settlement agreement?

A. Much has occurred in the past four years that has made it evident that a retail competitive electric industry not only has not developed, but also is fraught with risk. In light of what has transpired since the signing of the settlement agreement, the parties, as well as the Commission in Decision No. 65154, have had to rethink their earlier positions. RUCO does not believe blind adherence to a previous position merely for consistency's sake is necessarily prudent. The foremost concern is protection of the public interest as well as the health of Arizona's largest electric utility.

Q. Did a competitive electric market, even as envisioned five years ago, have any real potential benefits for residential customers?

A. No. The envisioned benefits were only of consequence for large commercial and industrial customers. Only through large scale aggregation was there much potential for residential customer benefit, and even then, the expected individual benefit was minimal. Thus, residential ratepayers should not be subject to the high level of risk that comes from a competitive electric market, given a relatively small potential for benefit.

Q. What actions does the Commission need to take in the instant docket to safeguard the public?

A. The electric competition rules need to be overturned or substantively revised, the 1999 settlement agreement declared expired and voided, and retail customers returned to rate of return regulation. The ACC already has a docket in place that is addressing the competition rules issue, and the remaining two issues (voiding of the settlement agreement and returning to regulation) can be resolved as part of the Commission order in this docket. RUCO's position on the two remaining issues identified here are discussed in greater detail later in my testimony.

PWEC ASSETS

Q. Please explain the treatment APS has proposed for the PWEC generation assets in this rate application.

A. APS proposes to include the Arizona PWEC generation assets[1] in its rate base at original cost and to include all revenues and expenses associated with those assets in operating income.

[1] Specifically, Redhawk 1, Redhawk 2, West Phoenix 4, West Phoenix 5, and Saguaro

Q. Did RUCO examine and analyze APS's proposal from a capacity, engineering, and macro-economic standpoint?

A. Yes. RUCO witness David Schlissel has examined the PWEC asset issue from various standpoints which are discussed in his direct testimony along with his recommended treatment in this case.

Q. What aspect of the PWEC asset issue are you responsible for?

A. I am responsible for RUCO's recommended ratemaking and accounting treatment of Mr. Schlissel's findings.

Q. What ratemaking treatment are you recommending for the PWEC assets?

A. At this time, I recommend that PWEC assets not be included in rate base until the least cost resources of APS's energy and capacity needs can be accurately determined. Mr. Schlissel explains in detail in his direct testimony the information that is needed to make this determination.

Q. How long of a delay do you anticipate between the Phase I portion of this case and the Phase II portion?

A. As explained in depth in Mr. Schlissel's testimony, a specific process is necessary to obtain the information to accurately determine the appropriate cost of APS's resource needs. Potentially the recent APS bid process could yield the necessary information, were the Commission to require that APS reveal the details of the bids received through that process. In that event, Phase II could commence within a relatively short time frame. Absent the detailed information from the recent bid process, commencement of Phase II would have to be delayed until APS completed a new bid process (or an auction and least-cost process as specifically described by Mr. Schlissel).

Q. Once the least cost value of APS's energy and capacity needs are determined how will such costs get reflected in rates?

A. RUCO recommends that this docket be divided into two phases. Phase I would be used to determine APS's revenue requirements for all current ratemaking elements, including costs of its Track B contracts. Phase II of this docket would proceed only after the least cost process explained by Mr. Schlissel is completed, and a determination will be made in Phase II of any necessary revenue requirement[2].

Q. Have you prepared a schedule that shows your recommended adjustments for the PWEC assets in the Phase I portion of this rate case?

A. Yes. Schedule MDC-3, Adjustment #1 shows the necessary rate base adjustment for the Phase I portion of this case, which decreases APS's proposed proforma rate base by $895,109,000. Schedule MDC-5,

[2] RUCO envisions that the Phase II portion of this docket would be patterned after the step rate increase methodology previously authorized in APS Decision No. 48319 (August 1, 1979), as limited by the Arizona Supreme Court in Arizona Community Action Association v. Arizona Corporation Commission, 123 Ariz. 228, 599 P.2d. 184 (1979). The step increase would only be necessary in Phase II if any of the PWEC assets prevail in the least cost process.

Adjustment #1 shows the necessary operating income adjustment for the Phase I portion of this case of $2,504,000. Collectively, these two adjustments remove all rate impacts of the PWEC assets from the Phase I portion of this proceeding. Pursuant to Mr. Schlissel's recommendations the rate impacts of APS's additional energy and capacity needs will be determined in Phase II of this docket.

PWEC INTEREST PREMIUM

Q. Is PWEC currently paying APS an interest premium on the debt that APS has secured on behalf of PWEC for financing of PWEC's generation assets?

A. Yes. Pursuant to Decision No. 65796 the Commission required PWEC to pay a 264 basis point interest premium to APS on the debt APS had secured to finance the PWEC assets. Decision No. 65796 also required that APS accrue the interest premiums in a deferral account for later credit to ratepayers.

Q. Has APS been accruing and deferring the interest premium as required by Decision No. 65796?

A. Yes. APS has requested an estimated premium accrual of $14.850 million through June 30, 2004. The Company is proposing to amortize this amount over 5 years in the current case, for an annual net credit (after calculation of a 6% return to customers on the deferral) of $3.416 million.

Thus, the Company's proposed ratemaking treatment would flow the interest premiums received by APS through June 30, 2004 to ratepayers.

Q. Has the Company made an adjustment to credit to ratepayers the on-going annual interest premiums paid by PWEC?

A. No. APS proposes to acquire these assets in the instant case and accordingly, would then carry the debt on its own behalf. Thus, there would no longer be an interest premium payment from PWEC.

Q. Under your recommendation regarding the PWEC assets in the Phase I portion of this case would PWEC continue to make interest premium payments to APS?

A. Yes. The debt arrangement between APS and PWEC would remain unchanged under my Phase I recommendations. Thus, as shown on Schedule MDC-6, Adjustment #2, I have made an adjustment to credit both the amortization of the deferred interest premium as well as the on-going annual premium to ratepayers. This adjustment increases operating income by $1.336 million.

THE 1999 SETTLEMENT AGREEMENT

Q. What is the status of the 1999 APS settlement agreement?

A. The current status of the 1999 APS settlement remains a question mark that must be resolved as part of this docket. The parties to recent APS proceedings have expressed differing opinions on the status of the agreement. These opinions range from the view that the agreement may have become null and void when Decision No. 65154 modified one of the terms of the agreement (divestiture), to the opinion that all terms of the agreement excepting the divestiture provision remain in full effect.

Q. What position does APS appear to have taken with regards the current status of the 1999 settlement agreement?

A. APS appears to have taken the position that those terms of the agreement to which it wants to abide remain in full effect and those terms to which it no longer wants to abide are null and void.

Q. Why does it appear that way?

A. APS has picked and chosen the terms of the 1999 settlement it considers still in effect vs. those it considers void. This is evident from positions APS has taken in previous dockets. For example, in the Adjustment Mechanism docket (E-01345A-02-0403) APS initially proposed a purchased power adjustor mechanism as provided for under the terms of the 1999 settlement agreement. Subsequently, after the issuance of Decision No. 65154, APS modified its proposed adjustor mechanism to include terms not provided for under the 1999 settlement, thus, showing it believed that specific term of the agreement was no longer valid. In the Financing docket (E-01345A-02-0707) APS witness Davis testified as follows regarding APS's view of the continued applicability of the various terms of the 1999 settlement agreement:

> As part of the consideration for allowing us to move our assets to the Pinnacle West Capital Corporation, we agreed to several things in the document. One was the $234 million write-off, which we took in the fourth quarter of 1999, and we also agreed in the document to only collect two-thirds of the transition costs. And with the, now, provision of the moving of the generation assets to Pinnacle West Energy Corporation being truncated, we think we are entitled to recovery of those costs. [Docket No. E-01345A-02-0707 transcription at page 692]

and

> Q. With reference to the settlement agreement, tell me what other provisions you think remain. You did mention one, the reduction in rates. Are there any further years in which the rates will be reduced?
> A. Yes, there's a rate reduction coming in July of this year.
> Q. And I take it that APS does not intend to rescind that part of the settlement agreement?
> A. That's not our intention. [Docket No. E-01345A-02-0707 transcript at page 692]

and

> Q. You have indicated that you believe that the settlement agreement is still in effect, is that not correct?
> A. Yes, I do.
> Q. And there are other parties to the settlement agreement, are there not?
> A. Yes, there are.
> Q. And I think you testified earlier that you have not conferred with those other parties concerning the rescinding of those other provisions that you've been discussing here just now?
> A. Not to my knowledge. But we certainly have been pretty public about what our intentions are. This is the first time I've heard any concern about it. [Docket No. E-01345A-02-0707 transcript at page 695]

Finally, APS again proposes in the instant docket to rescind the term of the 1999 settlement agreement that provided for a regulatory write-off of $234 million.

Q. Should APS be allowed to pick and choose the individual terms of the 1999 settlement agreement to which it will continue to adhere?

A. No. By definition negotiated agreements involve some give and take from each of the parties. One party gives up something it wants in return for getting something else. Without such give and take on part of the parties to a negotiation, there will be no agreement. The terms of the settlement agreement therefore are intrinsically entwined and modification of even one term can bias and/or void the entire agreement.

Q. Should the Commission render the 1999 settlement agreement null and void in this docket?

A. Yes. The status of the 1999 agreement needs to be defined thereby putting to rest any ambiguity. The assumptions that were the foundation of the 1999 settlement agreement have not come to pass (i.e. retail competition). Thus, the terms of that agreement are inapplicable in the current environment. The 1999 agreement itself foresaw the possibility of this situation and included the following provisions:

> This Agreement establishes the agreed upon transition for APS to a restructured entity and will provide customers with competitive choices for generation and certain other retail services. The parties believe this Agreement will produce benefits for all customers

> through implementing customer choice and providing rate reductions so the APS service territory may benefit from economic growth. [Decision No.61973, Attachment 1, page 1]

and

> The Parties acknowledge that APS' ability to offer retail access is contingent upon numerous conditions and circumstances, a number of which are not within the direct control of the Parties. Accordingly, the Parties agree that it may become necessary to modify the terms of the retail access to account for such factors, and they further agree to address such matters in good faith and to cooperate in an effort to propose joint resolutions of any such matters. [Decision No. 61973, Attachment I, section 1.3]

The retail competition that was the cornerstone of the 1999 agreement has not materialized. Pursuant to the agreement at page 2, paragraph 1.3, RUCO's proposed resolution is to end retail direct access and return to rate of return regulation, which will render the 1999 settlement void.

Q. Will voiding the 1999 settlement agreement at this junction result in the non-performance of any of its terms?

A. No, I do not believe so. With the exception of the divestiture requirement, the principle terms of the agreement have already been fulfilled as following:

* The APS distribution system was opened to retail access per section 1.1 of the agreement;
* The unbundled rates provided for in section 2.1 of the agreement have been implemented;

* The rate reductions provided for in paragraph 2.2 of the agreement became effective on the agreed upon dates;
* The adjustment clauses provided for in section 2.6 of the agreement have been acted upon by the Commission;
* The rate case required under section 2.7 of the agreement has been filed;
* The stranded cost recovery allowed in section 3.3 of the agreement has been realized by APS;
* The write-off required in section 3.3 was recorded on APS's books in 1999;
* The regulatory assets are being amortized as required in section 3.4 of the agreement.; and
* All parties have withdrawn their various court appeals in accordance with section 5.1 of the agreement.

Thus, the parties have fulfilled their obligations under the agreement and on a going forward basis there are no outstanding actions required by any of the parties. The agreement serves no future purpose nor is it applicable to rate of return regulation, to which RUCO recommends APS return at this juncture. Thus, no party will be left unwhole by the expiration of the agreement.

Q. Is the Company proposing in this docket to undo some of the previously acted upon terms of the agreement?

A. Yes. In this rate case the Company is requesting authority to reinstate the $234 million it agreed to write off in the 1999 agreement.

Q. Is this a fair and reasonable request?

A. No. As just discussed, the terms of the agreement represent a set of trade-offs agreed to by the parties which are intrinsically enmeshed. Given that all terms of the agreement have been fulfilled it would be unreasonable and biased to go back and retroactively undo the effect of select terms of the agreement. As previously discussed, the only aspect of the agreement that was altered by Decision No. 65154 was that of generation divesture. The divestiture provision of the agreement was included because the Commissioners supported it, and was not a part of the parties' negotiation.

Just as it would be unreasonable for RUCO to renege on its agreement to allow recovery of the stranded costs or recovery of the prudently incurred deferred transition costs after the fact, so it is unreasonable for the Company to renege on its agreement to the $234 million write-off.

Q. What adjustment is RUCO recommending regarding APS's request to reinstate the $234 write-off in the 1999 settlement agreement?

A. As shown on Schedule MDC-3, Adjustment #2 I have removed the Company's proforma adjustment to reinstate the $234 million write-off, net of deferred income taxes. I have also removed the Company's proposed $15.6 million annual amortization of the write-off from operating expenses, as shown on MDC-5, Adjustment #7.

INTERIM SPENT FUEL STORAGE

Q. Please discuss the Company's Interim Spent Fuel Storage Installation (ISFSI).

A. Due to delays in the US Department of Energy's siting and constructing of a permanent spent nuclear fuel storage facility, the Palo Verde nuclear plants required an interim alternative storage solution. That solution is a dry storage facility for spent nuclear fuel at the Palo Verde Generating Station. The accrued cost of this facility as of the end of the test year was $46,140,000 and APS estimates the accruals will reach $50,461,000 by the time rates from this docket go into effect in June 2004.

Q. What is the basis of the accrued amounts?

A. The accruals are based the annual levels of generation at Palo Verde multiplied by a factor representing the storage cost per unit of generation. Thus, the accruals do not represent actual expenditures made, but rather a pro rata annual allocation of the total estimated cost of the ISFSI. This has occurred because of a timing difference between when the Company made the accruals vs. when actual expenditures were made.

Q. What ratemaking treatment is the Company requesting for these costs?

A. The Company's requested ratemaking treatment is three fold. APS is requesting rate base treatment of the $50,461,000 in deferred ISFSI accruals, amortization expense for these deferred balances, and recovery of the annual on-going cost of the ISFSI.

Q. Do you agree with the Company's proposed ratemaking treatment?

A. In part. Spent nuclear fuel qualifies as a System's Benefit Charge under the Arizona Administrative Code and certainly is a cost of providing electric service through the Palo Verde plants. Thus, RUCO agrees that amortization of the accrued cost of storage and recovery of the annual go-forward cost of storage are appropriate. However, I do not agree with the Company's proposal to rate base the deferred balance.

Q. Why not?

A. Under rate of return regulation a utility is entitled to earn a return on its capital invested for the public service. In the case of the ISFSI deferrals, APS has virtually no invested capital. The ISFSI deferred balance does not represent actual expenditures made by the Company, but rather mere accounting accruals. The deferred balance requested by APS in rate base is over $50 million, yet APS's actual expenditures on the ISFSI to date are approximately $5 million. Since APS has not actually made a $50 million investment it is not entitled to a return on $50 million.

Q. What adjustment have you made?

A. As shown on Schedule MDC-3, Adjustment #3 I have decreased rate base by $50,461,000 to remove the ISFSI accruals.

DIRECT ACCESS EXPENSES

Q. What ratemaking treatment is APS requesting for its costs to comply with the electric competition rules?

A. The Company is seeking recovery of $34,013,000 in direct access expenses that it had deferred for future recovery pursuant to section 2.6, item (3) of the 1999 settlement agreement. The Company is requesting a five year amortization of these direct access deferrals, or $6,802,5000 in annual amortization expense.

Q. Is the Company requesting rate base treatment of the direct access expenses deferrals?

A. No. The 1999 settlement agreement granted APS the authority to defer these expenses as well as accrue returns on the deferred amounts. Thus, the Company's return on the deferred amounts is already included in the proposed amortization expense.

Q. Do you agree with the Company's proposed ratemaking treatment of the direct access expense deferrals?

A. Yes. The Company's proposed ratemaking treatment of the deferred direct access expenses comports with the terms of the 1999 settlement agreement. While RUCO recommends the voiding of the agreement on a going forward basis, it does not recommend reneging on the terms of the agreement on a retrospective basis.

Q. Is APS requesting any direct access expenses beyond the just described deferrals provided for in the settlement agreement?

A. Yes. APS is requesting an additional $1,477,000 annually to cover its estimated on-going annual cost of compliance with the electric competition rules.

Q. Do you agree that an on-going level of expense needs to be provided?

A. No. As discussed earlier, a retail competitive market has failed to develop in Arizona and even if it were to develop, it is fraught with unacceptable risk to retail customers. Thus, RUCO has recommended a return to retail rate of return regulation. Accordingly, there will be no on-going cost to comply with the electric competition rules.

Q. What adjustment have you made?

A. As shown on Schedule MDC-5, Adjustment #3 , I have reduced test year operating expenses by $1,477,000 to remove the estimated cost of on-going compliance with the electric competition rules.

TRANSMISSION ASSETS AND EXPENSES

Q. Have you included an adjustment in your recommended revenue requirements to reflect the position of RUCO Witness Richard Rosen regarding APS's transmission pricing?

A. No. Through data requests RUCO asked the Company to provide a break-out of its transmission costs between wholesale and retail, as defined in Mr. Rosen's testimony. The Company did not provide this information, therefore, I am unable to reflect the impact of Mr. Rosen's recommendation on RUCO's recommended revenue requirements.

Q. Is the necessary adjustment likely to be very material?

A. No. Transmission costs are a small portion of APS's overall expenses and the necessary adjustment would merely be the difference between the FERC OATT and APS's cost to serve transmission. Mr. Rosen's recommendation for retail transmission to remain under ACC jurisdiction is based primarily on the desirability of retaining local control over this aspect of APS's operations as opposed to its revenue requirement effects.

Q. Do you intend to update your testimony at a later date with this information?

A. Hopefully, APS will provide this information, or potentially RUCO could estimate the wholesale/retail allocation once its cost of service study is complete.

ENVIRONMENTAL PORTFOLIO STANDARD AND DEMAND SIDE MANAGEMENT FUNDING

Q. What amount is currently included in APS's rates to fund Demand Side Management (DSM) programs and Environmental Portfolio Standard (EPS) projects?

A. Included in APS's current base rates is $6 million in funding originally earmarked for DSM programs. It is my understanding that pursuant to Decision No. 63364 APS has redirected the DSM base rate funding to EPS projects. APS also receives additionally funding for EPS projects through the EPS surcharge. This charge provides approximately $6.5 million in funding per year.

Q. Given your recommendation that retail customers should be returned to rate of return regulation do you believe the current allocation of the EPS and DSM funds is appropriate?

A. No. The current allocation between DSM and EPS funding is 100% for the EPS. While this allocation maybe appropriate in a competitive retail market, it is not in a regulated rate of return model, as I am recommending. Under the regulated model, DSM can be a very effective tool in controlling load growth, mitigating the need to acquire additional capacity, allowing customers to control their electric bill as well as promoting conservation. I am therefore recommending the $6 million in current base rate funding be redirected from EPS projects to DSM programs, as was originally intended.

Q. How would the EPS continue to be funded?

A. The EPS would continue to be funded through the EPS surcharge. Thus, my recommendation to reassign the $6 million in base rates from EPS to DSM does not mean that EPS would not continue to be funded through the surcharge at what is ultimately determined to be an adequate level.

Q. Is any adjustment necessary to the ratemaking model to reflect the reassignment of $6 million in rate base funding from EPS to DSM?

A. No adjustment is necessary for the reassignment. However, a small adjustment is necessary to correct an error in the Company's calculation. The Company has incorrectly recognized $5.263 million in base rate revenue for the EPS programs and $6 million in EPS expenditures, thereby mathematically creating an additional revenue requirement of $737,000. Base rates provide for $6 million in revenue not $5.263 million.

On Schedule MDC-5, Adjustment #4 I have corrected this calculation, which increases test year revenues by $737,000.

FUTURE DEMAND SIDE MANAGEMENT PROGRAMS

Q. Does your recommended reassignment of $6 million from EPS to DSM provide adequate funding for an aggressive level of DSM?

A. No.

Q. Is RUCO advocating an aggressive approach to DSM?

A. Yes. Well planned and funded DSM programs can go a long way to control load growth, forego or at least forestall additional investment in energy and capacity, as well as provide tools for customer bill management. DSM programs when properly designed and administered can be very cost effective. In fact, statistics show that APS's DSM programs historically have generated more benefit per dollar expended vs. industry averages. An aggressive DSM approach in a regulated monopoly model, as RUCO is recommending here, can generate significant savings and benefits for ratepayers as well as stockholders.

Q. How much additional funding are you recommending for DSM programs?

A. RUCO is recommending an additional $29 million in funding for DSM programs, for a total DSM funding of $35 million per year. The recommended funding level is equivalent to an overall amount accumulated from a 1.5 mil charge on all kWh usage. RUCO's adjustment to include this additional DSM funding in rates is shown on Schedule MDC-5, Adjustment #5.

Q. Are you recommending that the Commission maintain continuing oversight on the use of the $35 million in DSM funding?

A. Yes. The mere provision of $35 million in funding for DSM does not ensure that reductions in load or load growth will be achieved. Although APS has historically made effective use of its DSM funding, I am recommending the following annual oversight and monitoring:

1) All programs will be subject to a preapproval process, where APS will be required to submit the details of all proposed programs to Staff for approval. The details submitted must include a cost benefit analysis that specifically provides estimated load reductions.

2) All approved programs will be subject to an annual review by Staff to determine the effectiveness of the programs. The review process will determine if a program is continued, modified, or replaced. Staff will also review the level of program expenditures and to the extent anything less or more than $35 million is utilized in any given year the difference will be preserved in a deferred balancing account. If the cumulative balance in this account is a credit (APS net expenditures were less than funded) at the time of the next rate case the under expenditures will be returned to

ratepayers. Any net debit balance in the balancing account will not be eligible for future recovery.

CONCLUSION

Q. Why should the positions' of the RUCO witnesses be adopted?

A. All the RUCO witnesses, utilizing their individual areas of utility expertise, worked as a team to put together recommendations that would address the loose ends and various risks that currently exist as a direct result of a vision of a functional retail electric market that never developed. RUCO's recommendations are designed to return ratepayers and shareholders alike to a regulatory foundation that is designed to protect the public interest. This will be accomplished through the return to rate of return regulation, finally laying to rest the provisions of the now inapt 1999 settlement agreement, and resolving out-dated competitive rules. RUCO's recommendation also ensures that APS acquires any additional energy and capacity resources at least cost, through the Phase II part of this case, provides a fair rate of return to stockholders, and takes an aggressive approach to DSM and conservation.

Q. Does RUCO's recommendation come with a large price tag?

A. No. RUCO's recommendation in the Phase I portion of this docket will result in a rate *decrease* of approximately 3%. This result clearly shows the rate decreases called for by the 1999 settlement agreement were fully warranted. RUCO's recommendation also provides a methodology, through Phase II of this docket, for ensuring that APS acquires its additional energy and capacity needs in the most prudent least-cost manner. RUCO urges the Commission to embrace its recommendations and support the return of APS to protected regulated status.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION:	University of Michigan, Dearborn B.S.A., Accounting 1989
CERTIFICATION:	Certified Public Accountant - Michigan Certified Public Accountant - Arizona
EXPERIENCE:	Audit Manager Residential Utility Consumer Office Phoenix, Arizona 85007 July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office

Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office

Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office

Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-03-0437
TABLE OF CONTENTS TO SCHEDULES MDC

SCHEDULE #

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	ADJUSTED RATE BASE	$ 4,207,476	$ 6,744,328	$ 5,475,902	$ 3,051,479	$ 5,078,693	$ 4,065,086
2	ADJUSTED OPERATING INCOME	263,870	263,870	263,870	258,992	258,992	258,992
3	CURRENT RATE OF RETURN (L2 / L1)	6.27%	3.91%	4.82%	8.49%	5.10%	6.37%
4	REQUIRED RATE OF RETURN	8.67%	5.41%	6.66%	7.43%	4.46%	5.57%
5	REQUIRED OPERATING INCOME (L4 * L1)	364,788	364,788	364,788	226,578	226,578	226,578
6	OPERATING INCOME DE(SUF)FICIENCY (L5 - L2)	100,918	100,918	100,918	(32,414)	(32,414)	(32,414)
7	GROSS REVENUE CONVERSION FACTOR	1.65290	1.65290	1.65290	1.65375	1.65375	1.65375
8	GROSS REVENUE INCREASE	$ 166,807	$ 166,807	$ 166,807	$ (53,605)	$ (53,605)	$ (53,605)
9	CURRENT REVENUES T/Y ADJUSTED	$ 1,940,146	$ 1,940,146	$ 1,940,146	$ 1,885,120	$ 1,885,120	$ 1,885,120
10	PROPOSED ANNUAL REVENUE (L8 + L9)	$ 2,106,953	$ 2,106,953	$ 2,106,953	$ 1,831,515	$ 1,831,515	$ 1,831,515
11	PERCENTAGE AVERAGE INCREASE	8.60%	8.60%	8.60%	-2.84%	-2.84%	-2.84%

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
ACC JURISDICTIONAL RCND RATE BASE (000'S)

LINE NO.	DESCRIPTION	(A) TOTAL COMPANY AS FILED	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO ADJUSTED TOTAL COMPANY	(D) RUCO ADJUSTED ACC JURISDICTIONAL
1	GROSS UTILITY PLANT IN SERVICE	$ 12,602,163	$ (1,562,070)	$ 11,040,093	$ 11,005,365
2	LESS: ACCUMULATED DEPRECIATION & AMORT.	(4,950,671)	116,610	(4,834,061)	(4,806,037)
3	NET UTILITY PLANT IN SERVICE	$ 7,651,492	$ (1,445,461)	$ 6,206,031	$ 6,199,327
4	DEDUCTIONS:				
5	LESS: TOTAL DEDUCTIONS	$ (1,605,285)	$ 147,519	$ (1,457,766)	$ (1,455,314)
6	TOTAL ADDITIONS	698,121	(359,900)	338,221	334,680
7	TOTAL RATE BASE	$ 6,744,328	$ (1,657,842)	$ 5,086,486	$ 5,078,693

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1
COLUMN (B): SCHEDULE MDC-3 x RCND FACTOR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) x JURISDICTIONAL FACTOR

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
GROSS REVENUE CONVERSION FACTOR (000'S)

LINE NO.	DESCRIPTION	TOTAL AMOUNT	REFERENCE
1	REVENUE	1.0000	
2	UNCOLLECTIBLES	-	COMPANY SCH. C-3
3	SUB-TOTAL	1.0000	LINE 1 - LINE 2
4	LESS: TAX RATE	39.53%	NOTE (a)
5	TOTAL	0.6047	LINE 3 - LINE 4
6	REVENUE CONVERSION FACTOR	$\boxed{1.65375}$	LINE 1/LINE 5

NOTE (a):
CALCULATION OF EFFECTIVE TAX RATE

OPERATING INCOME BEFORE TAXES	100.00%
ARIZONA STATE TAX	6.97%
TAXABLE INCOME FEDERAL	93.03%
FEDERAL INCOME TAX RATE	35.00%
SUBTOTAL	32.56%
ADD STATE TAX RATE	39.53%
LINE 3 ABOVE	100.00%
EFFECTIVE TAX RATE	39.53%

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
ORIGINAL COST RATE BASE (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO TEST YEAR AS ADJUSTED TOTAL COMPANY	(D) RUCO TEST YEAR AS ADJUSTED ACC JURISDICTION
1	GROSS UTILITY PLANT IN SERVICE	$ 8,244,170	$ (1,021,886)	$ 7,222,284	$ 7,198,657
2	LESS: ACCUMULATED DEPRECIATION & AMORT.	(3,115,987)	73,395	(3,042,592)	(3,024,981)
3	NET UTILITY PLANT IN SERVICE	**$ 5,128,183**	**$ (948,491)**	**$ 4,179,692**	**$ 4,173,676**
	DEDUCTIONS:				
4	DEFERRED TAXES	$ (1,282,822)	$ 147,519	$ (1,135,303)	$ (1,133,906)
5	INVESTMENT TAX CREDITS	(4,040)	-	(4,040)	(4,033)
6	CUSTOMER ADVANCES FOR CONSTRUCTION	(45,513)	-	(45,513)	(45,513)
7	CUSTOMER DEPOSITS	(39,865)	-	(39,865)	(39,865)
8	PENSION LIABILITY	(49,511)	-	(49,511)	(48,751)
9	OTHER DEFERRED CREDITS	(124,050)	-	(124,050)	(123,798)
10	UNAMORTIZED GAIN - SALE OF UTILITY PLANT	(59,484)	-	(59,484)	(59,381)
11	TOTAL DEDUCTIONS	**$ (1,605,285)**	**$ 147,519**	**$ (1,457,766)**	**$ (1,455,247)**
	ADDITIONS:				
12	REGULATORY ASSETS/LIABILITIES NET	$ 300,589	$ (284,461)	$ 16,128	$ 16,087
13	MISCELLANEOUS DEFERRED DEBITS	27,379	-	27,379	26,959
14	DEPRECIATION FUND - DECOMMISSIONING	194,440	-	194,440	191,608
15	ALLOWANCE FOR WORKING CAPITAL	175,713	(75,439)	100,274	98,396
16	TOTAL ADDITIONS	**$ 698,121**	**$ (359,900)**	**$ 338,221**	**$ 333,050**
17	TOTAL RATE BASE	**$ 4,221,019**	**$ (1,160,872)**	**$ 3,060,147**	**$ 3,051,479**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1
COLUMN (B): SCHEDULE MDC-3
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) x APPROPRIATE JURISDICTIONAL FACTOR

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
SUMMARY OF RATE BASE ADJUSTMENTS (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE MDC-3

LINE NO.	DESCRIPTION	(A) TOTAL COMPANY	(B) ADJ. #1	(C) ADJ. #2	(D) ADJ. #3	(E) ADJ. #4	(F) ADJ. #5	(G) RUCO ADJUSTED TOTAL COMPANY
1	GROSS UTILITY PLANT IN SERVICE	$ 8,244,170	$ (1,021,886)		$ -	$ -	$ -	$ 7,222,284
2	LESS: ACCUMULATED DEPRECIATION & AMORT.	(3,115,987)	73,395					(3,042,592)
3	NET UTILITY PLANT IN SERVICE	$ 5,128,183	$ (948,491)	$ -	$ -	$ -	$ -	$ 4,179,692
	DEDUCTIONS:							
4	DEFERRED TAXES	$ (1,282,822)	53,382	$ 92,430	$ 1,707	$ -	$ -	$ (1,135,303)
5	INVESTMENT TAX CREDITS	(4,040)						(4,040)
6	CUSTOMER ADVANCES FOR CONSTRUCTION	(45,513)						(45,513)
7	CUSTOMER DEPOSITS	(39,865)						(39,865)
8	PENSION LIABILITY	(49,511)						(49,511)
9	OTHER DEFERRED CREDITS	(124,050)						(124,050)
10	UNAMORTIZED GAIN - SALE OF UTILITY PLANT	(59,484)						(59,484)
11	TOTAL DEDUCTIONS	$ (1,605,285)	$ 53,382	$ 92,430	$ 1,707	$ -	$ -	$ (1,457,766)
	ADDITIONS:							
12	REGULATORY ASSETS/LIABILITIES NET	$ 300,589	$ -	$ (234,000)	$ (50,461)	$ -	$ -	$ 16,128
13	MISCELLANEOUS DEFERRED DEBITS	27,379						27,379
14	DEPRECIATION FUND - DECOMMISSIONING	194,440						194,440
15	ALLOWANCE FOR WORKING CAPITAL	175,713					(75,439)	100,274
16	TOTAL ADDITIONS	$ 698,121	$ -	$ (234,000)	$ (50,461)	$ -	$ (75,439)	$ 338,221
17	TOTAL RATE BASE	$ 4,221,019	$ (895,109)	$ (141,570)	$ (48,754)	$ -	$ (75,439)	$ 3,060,147

ADJUSTMENT #:	REFERENCE:
1. REMOVE PWEC ASSETS	DIRECT TESTIMONY MDC
2. REINSTATE SETTLEMENT WRITE-OFF	DIRECT TESTIMONY MDC
3. ISFSI ACCRUALS	DIRECT TESTIMONY MDC
4. RESERVED FOR TRANSMISSION ASSETS	DIRECT TESTIMONY ROSEN
5. WORKING CAPITAL	SCHEDULE WAR-1

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME - TEST YEAR AND RUCO PROPOSED (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE MDC-4

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO TEST YEAR AS ADJUSTED TOTAL COMPANY	(D) RUCO TEST YEAR AS ADJUSTED ACC JURISDICTION	(E) RUCO PROPOSED CHANGES ACC JURISDICTION	(F) RUCO RECOMMENDED ACC JURISDICTION
1	ELECTRIC OPERATING REVENUES	$ 1,978,176	$ (56,105)	$ 1,922,071	$ 1,885,120	$ (53,605)	$ 1,831,515
2	LESS: FUEL & PURCHASED POWER COSTS	568,870	34,946	603,816	594,272		594,272
3	TOTAL OPERATING REVENUES	**$ 1,409,306**	**$ (91,050)**	**$ 1,318,256**	**$ 1,290,848**	**$ (53,605)**	**$ 1,237,242**
4	OTHER OPERATING EXPENSES:						
5	OPERATIONS AND MAINTENANCE	$ 616,060	$ (34,685)	$ 581,375	$ 556,852	$ -	$ 556,852
6	DEPRECIATION AND AMORTIZATION	331,492	(57,141)	274,351	273,102		273,102
7	INCOME TAXES	86,606	20,679	107,285	106,728	(21,191)	85,537
8	OTHER TAXES	110,144	(15,016)	95,128	95,174		95,174
9	TOTAL OPERATING EXPENSES OTHER THAN FUEL & POWER	**$ 1,144,302**	**$ (86,162)**	**$ 1,058,140**	**$ 1,031,856**	**$ (21,191)**	**$ 1,010,664**
10	OPERATING INCOME	**$ 265,004**	**$ (4,888)**	**$ 260,116**	**258,992**	**$ (32,414)**	**$ 226,578**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C-1
COLUMN (B): SCHEDULE MDC-5
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (E) x APPROPRIATE JURISDICTIONAL FACTOR
COLUMN (E): SCHEDULE MDC-1
COLUMN (F): COLUMN (D) + COLUMN (E)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE MDC-5

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED TOTAL COMPANY	(B) ADJ. #1	(C) ADJ. #2	(D) ADJ. #3	(E) ADJ. #4	(F) ADJ. #5	(G) ADJ. #6	(H) ADJ. #7
1	ELECTRIC OPERATING REVENUES	$ 1,978,176	$ (56,779)	$ -	$ -	$ 737	$ -	$ -	$ -
2	LESS:								
3	FUEL FOR ELECTRIC GENERATION:								
4	COAL	$ 138,717	$ 8,691	$ -	$ -	$ -	$ -	$ -	$ -
5	NATURAL GAS	49,320	$ 3,090						
6	FUEL OIL	1,220	$ 76						
7	NUCLEAR:								
8	AMORTIZATION	26,740	$ 1,675						
9	SPENT FUEL	11,178	$ 700						
10	TOTAL FUEL FOR ELECTRIC GENERATION	$ 227,175	$ 14,234	$ -	$ -	$ -	$ -	$ -	$ -
11	LESS:								
12	PURCHASED POWER & TRANSMISSION:								
13	PURCHASED POWER	$ 330,952	$ 20,736	$ -	$ -	$ -	$ -	$ -	$ -
14	TRANSMISSION BY OTHERS	10,743							
15	TOTAL PURCHASED POWER & TRANSMISSION BY OTHERS	$ 341,695	$ 20,736	$ -	$ -	$ -	$ -	$ -	$ -
16	TOTAL FUEL & PURCHASED POWER COSTS	$ 568,870	$ 34,970	$ -	-	$ -	$ -	$ -	$ -
17	TOTAL OPERATING REVENUES	$ 1,409,306	$ (91,749)	$ -	$ -	$ 737	$ -	$ -	$ -
18	OTHER OPERATIONS & MAINTENANCE:								
19	PAYROLL	$ 218,822	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	SEVERANCE	5,068							
21	PENSION AND OPEB	45,964							
22	EMPLOYEE BENEFITS	17,723							
23	PAYROLL TAXES	13,677							
24	MATERIALS & SUPPLIES	52,358							
25	FRANCHISE PAYMENTS	-							
26	VEHICLE LEASE PAYMENTS	7,228							
27	RENTS	5,649							
28	PALO VERDE LEASE	45,202							
29	PALO VERDE SALE/LOSS GAIN AMORT.	(4,576)							
30	INSURANCE	2,431							
31	UNCOLLECTIBLE ACCOUNTS	2,680							
32	OTHER	203,834	(41,456)	(1,336)	(1,477)		29,000		
33	TOTAL OTHER OPERATIONS AND MAINTENANCE	$ 616,060	$ (41,456)	$ (1,336)	$ (1,477)	$ -	$ 29,000	$ -	$ -
34	DEPRECIATION & AMORTIZATION:								
35	DEPRECIATION & AMORTIZATION	$ 331,492	$ (41,541)	$ -	$ -	$ -	$ -	$ -	$ (15,600)
36	AMORT. OF ELECTRIC PLANT ACQ. ADJ.	-							
37	AMORT. OF PROP. LOSSES & REG. STUDY COSTS	-							
38	TOTAL DEPRECIATION & AMORTIZATION	$ 331,492	$ (41,541)	$ -	$ -	$ -	$ -	$ -	$ (15,600)
39	INCOME TAXES:								
40	CURRENT:								
41	FEDERAL & STATE	$ 86,606	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	DEFERRED	-							
43	TOTAL INCOME TAXES	$ 86,606	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	OTHER TAXES:								
45	PROPERTY TAXES	$ 106,189	$ (11,256)	$ -	$ -	$ -	$ -	$ -	$ -
46	SALES TAXES	3,955							
47	TOTAL OTHER TAXES	$ 110,144	$ (11,256)	$ -	$ -	$ -	$ -	$ -	$ -
48									
49	TOTAL OPERATING EXPENSES OTHER THAN FUEL & POWER	$ 1,144,302	$ (94,253)	$ (1,336)	$ (1,477)	$ -	$ 29,000	$ -	$ (15,600)
50	OPERATING INCOME	$ 265,004	$ 2,504	$ 1,336	$ 1,477	$ 737	$ (29,000)	$ -	$ 15,600

ADJUSTMENT #:	REFERENCE:
1. REMOVE PWEC EXPENSES	DIRECT TESTIMONY MDC
2. AMORTIZATION OF PWEC INTEREST PREMIUM	SCHEDULE MDC-6
3. REMOVE DIRECT ACCESS EXPENSE	DIRECT TESTIMONY MDC
4. CORRECT EPS REVENUES	DIRECT TESTIMONY MDC
5. RUCO PROPOSED DSM LEVEL	DIRECT TESTIMONY MDC
6. RESERVED FOR TRANSMISSION EXPENSES	DIRECT TESTIMONY ROSEN
7. REINSTATE SETTLEMENT WRITE-OFF	DIRECT TESTIMONY MDC

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE MDC-5

LINE NO.	DESCRIPTION	(I) ADJ. #8	(J) ADJ. #9	(K) ADJ. #10	(L) ADJ. #11	(M) ADJ. #12	(N) ADJ. #13	(O) ADJ. #14	(P) ADJ. #15	(Q) RUCO ADJUSTED TOTAL COMPANY
1	ELECTRIC OPERATING REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (63)	$ 1,922,071
2	LESS:									
3	FUEL FOR ELECTRIC GENERATION:									
4	COAL	$ (8)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147,400
5	NATURAL GAS	(8)								52,402
6	FUEL OIL	(8)								1,288
7	NUCLEAR:									-
8	AMORTIZATION									28,415
9	SPENT FUEL									11,878
10	TOTAL FUEL FOR ELECTRIC GENERATION	$ (24)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 241,385
11	LESS:									
12	PURCHASED POWER & TRANSMISSION:									
13	PURCHASED POWER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 351,688
14	TRANSMISSION BY OTHERS									10,743
15	TOTAL PURCHASED POWER & TRANSMISSION BY OTHERS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 362,431
16	TOTAL FUEL & PURCHASED POWER COSTS	$ (24)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 603,816
17	TOTAL OPERATING REVENUES	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ (63)	$ 1,318,256
18	OTHER OPERATIONS & MAINTENANCE:									
19	PAYROLL	$ (68)	$ -	$(11,056)	$ -	$ -	$ -	$ -	$ -	$ 207,698
20	SEVERANCE		(6,972)							(1,904)
21	PENSION AND OPEB									45,964
22	EMPLOYEE BENEFITS									17,723
23	PAYROLL TAXES									13,677
24	MATERIALS & SUPPLIES									52,358
25	FRANCHISE PAYMENTS									-
26	VEHICLE LEASE PAYMENTS									7,228
27	RENTS									5,649
28	PALO VERDE LEASE									45,202
29	PALO VERDE SALE/LOSS GAIN AMORT.									(4,576)
30	INSURANCE									2,431
31	UNCOLLECTIBLE ACCOUNTS									2,680
32	OTHER				(965)	(354)				187,246
33	TOTAL OTHER OPERATIONS AND MAINTENANCE	$ (68)	$ (6,972)	$(11,056)	$ (965)	$ (354)	$ -	$ -	$ -	$ 581,375
34	DEPRECIATION & AMORTIZATION:									
35	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 274,351
36	AMORT. OF ELECTRIC PLANT ACQ. ADJ.									-
37	AMORT. OF PROP. LOSSES & REG. STUDY COSTS									-
38	TOTAL DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 274,351
39	INCOME TAXES:									
40	CURRENT:									
41	FEDERAL & STATE	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,679	$ -	$ 107,285
42	DEFERRED									-
43	TOTAL INCOME TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,679	$ -	$ 107,285
44	OTHER TAXES:									
45	PROPERTY TAXES	$ -	$ -	$ -	$ -	$ -	$ (3,760)	$ -	$ -	$ 91,173
46	SALES TAXES									3,955
47	TOTAL OTHER TAXES	$ -	$ -	$ -	$ -	$ -	$ (3,760)	$ -	$ -	$ 95,128
48										
49	TOTAL OPERATING EXPENSES OTHER THAN FUEL & POWER	$ (68)	$ (6,972)	$(11,056)	$ (965)	$ (354)	$ (3,760)	$ 20,679	$ -	$ 1,058,140
50	OPERATING INCOME	$ 93	$ 6,972	$ 11,056	$ 965	$ 354	$ 3,760	$ (20,679)	$ (63)	$ 260,116

ADJUSTMENT #:	REFERENCE:
8. NORMALIZE PAYROLL	SCHEDULE WAR-2
9. EMPLOYEE SEVERANCE	SCHEDULE WAR-3
10. REMOVE INCENTIVE PAY	DIRECT TESTIMONY WAR
11. REMOVE AVNET SOFTWARE LEASE EXPENSE	DIRECT TESTIMONY WAR
12. INTEREST ON CUSTOMER DEPOSITS	SCHEDULE WAR-4
13. PROPERTY TAXES	SCHEDULE WAR-5
14. INCOME TAXES	SCHEDULE WAR-6
15. SCHEDULE 1 CHANGES	SCHEDULE WAR-7

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME ADJUSTMENT #2 - AMORTIZATION OF OF PWEC INTEREST PREMIUM

DOCKET NO. E-01345A-03-0437
SCHEDULE MDC-6

LINE NO.	DATE	(A) OUTSTANDING BALANCE	(B) TOTAL PAYMENT	(C) PRINCIPLE PAYMENT	(D) INTEREST PAYMENT	(E) ENDING BALANCE
1	15-May-03	$ 500,000,000			$ -	$ 500,000,000
2	1-Jan-04	500,000,000	56,600,000	50,000,000	6,600,000	450,000,000
3	1-Jul-04	450,000,000	55,940,000	50,000,000	5,940,000	400,000,000
4	1-Jan-01	400,000,000	55,280,000	50,000,000	5,280,000	350,000,000
5	1-Jul-05	350,000,000	54,620,000	50,000,000	4,620,000	300,000,000
6	1-Jan-06	300,000,000	53,960,000	50,000,000	3,960,000	250,000,000
7	1-Jul-06	250,000,000	53,300,000	50,000,000	3,300,000	200,000,000
8	1-Jan-07	200,000,000	52,640,000	50,000,000	2,640,000	150,000,000
9	1-Jul-07	150,000,000	51,980,000	50,000,000	1,980,000	100,000,000
10	1-Jan-08	100,000,000	51,320,000	50,000,000	1,320,000	50,000,000
11	1-Jul-08	50,000,000	50,660,000	50,000,000	660,000	-
12	INTEREST EARNED 1 JULY 04 THROUGH 1 JULY 08				$ 23,760,000	
13	5 YEAR AMORTIZATION				$ 4,752,000	
14	PER COMPANY				$ 3,416,000	
15	ADJUSTMENT				$ 1,336,000	

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
COST OF CAPITAL

DOCKET NO. E-01345A-03-0437
SCHEDULE MDC-7

LINE NO.	TYPE OF CAPITAL	(A) PERCENT	(B) COST RATE	(C) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	45.14%	9.50%	4.29%
2	LONG-TERM DEBT	53.83%	5.77%	3.11%
3	SHORT-TERM DEBT	1.03%	3.00%	0.03%
4	TOTAL CAPITAL	100.00%		7.43%

PRE-TAX INTEREST COVERAGE = 3.28X (a)

REFERENCES:
COLUMN (A): TESTIMONY, STEPHEN G. HILL
COLUMN (B): TESTIMONY, STEPHEN G. HILL
COLUMN (C): COLUMN (A) x COLUMN (B)

NOTE:
(a) ASSUMING THE COMPANY EXPERIENCES, PROSPECTIVELY, AN INCOME TAX RATE OF 40.00%, THE PRE-TAX OVERALL RETURN WOULD BE 10.28% [7.43% - (3.11% + 0.03%) = 4.29% / (1 - 40.00%) = 7.15% + (3.11% + 0.03%)]. THAT PRE-TAX OVERALL RETURN, 10.28%, DIVIDED BY THE WEIGHTED COST OF DEBT (3.11% + 0.03%), INDICATES A PRE-TAX INTEREST COVERAGE OF 3.28 TIMES.

IN THE MATTER OF

ARIZONA PUBLIC SERVICE COMPANY

BEFORE THE

ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 3, 2004

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

TABLE OF CONTENTS

INTRODUCTION / SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is Stephen G. Hill. I am self-employed as a financial consultant, and principal of Hill Associates, a consulting firm specializing in financial and economic issues in regulated industries. My business address is P.O. Box 587, Hurricane, West Virginia, 25526 (e-mail: sghill@compuserve.com).

Q. BRIEFLY, WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. After graduating with a Bachelor of Science degree in Chemical Engineering from Auburn University in Auburn, Alabama, I was awarded a scholarship to attend Tulane Graduate School of Business Administration at Tulane University in New Orleans, Louisiana. There I received a Master's Degree in Business Administration. More recently, I have been awarded the professional designation "Certified Rate of Return Analyst" by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience and the successful completion of a comprehensive examination. I have also recently been asked to be on the Board of Directors of that national organization. A more detailed account of my educational background and occupational experience appears in Appendix A.

Q. HAVE YOU TESTIFIED BEFORE THIS OR OTHER REGULATORY COMMISSIONS?

A. Yes, I have appeared previously before this Commission on many occasions. In addition, I have testified on cost of capital, corporate finance and capital market issues in more than 210 regulatory proceedings before the following regulatory bodies: the West Virginia Public Service Commission, the Texas Public Utilities Commission, the Oklahoma State Corporation Commission, the Public Utilities Commission of the State of California, the Public Service Commission of the State of Maine, the Maryland Public Service Commission, the Public Utilities Commission of the State of Minnesota, the Ohio Public Utilities Commission, the Insurance Commissioner of the State of Texas, the North Carolina Insurance Commissioner, the Rhode Island Public Utilities Commission, the City

Council of Austin, Texas, the Missouri Public Service Commission, the South Carolina Public Service Commission, the Public Utilities Commission of the State of Hawaii, the New Mexico Corporation Commission, the State of Washington Utilities and Transportation Commission, the Georgia Public Service Commission, the Public Service Commission of Utah, the Illinois Commerce Commission, the Kansas Corporation Commission, the Indiana Utility Regulatory Commission, the Virginia Corporation Commission, the Montana Public Service Commission, the Pennsylvania Public Utilities Commission, the Public Service Commission of Wisconsin, the Vermont Public Service Board, the Federal Communications Commission and the Federal Energy Regulatory Commission. I have also testified before the West Virginia Air Pollution Control Commission regarding appropriate pollution control technology and its financial impact on the company under review and have been an advisor to this Commission on matters of utility finance.

O. ON BEHALF OF WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Residential Utility Consumer Office (RUCO).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony, I present the results of studies I have performed related to the establishment of an appropriate return on equity and overall cost of capital for the electric utility operations of Arizona Public Service Company (APS, the Company), a subsidiary of Pinnacle West Capital Corp. (PWC, Pinnacle West, the Parent). In addition to my testimony regarding the Company's current cost of capital, I review the cost of capital testimony provided by Dr. Charles Olson and discuss the shortcomings contained therein.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, Exhibit_(SGH-1) consists of 12 Schedules and provides the analytical support for the conclusions reached regarding the overall cost of capital for Arizona Public Service Company presented in the body of the testimony. This Exhibit was prepared by me and is correct to the best of my knowledge and belief. Also, I have provided four Appendices

("A" through "D"), which contain additional detail regarding certain aspects of my narrative testimony in this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR APS's ARIZONA ELECTRIC UTILITY OPERATIONS IN THIS PROCEEDING.

A. My testimony is organized into four sections. First, I discuss the cost of capital standard as a measure of the return to be allowed for regulated industries, and review the current economic environment in which the equity return estimate is made. Second, I review the capital structure requested by APS for ratemaking purposes in comparison to capital structures employed by the Company historically as well as those existing in the utility industry today. From that review, I develop a capital structure appropriate for ratemaking purposes.

Third, I evaluate the cost of equity capital for similar-risk utility operations using Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Modified Earnings-Price Ratio (MEPR), and Market-to-Book Ratio (MTB) analyses. Fourth, I comment on the pre-filed cost of capital testimony submitted by Company witness, Dr. Charles Olson.

I have estimated the equity capital cost of electric utility companies to fall in a range of 9.25% to 9.75%. Within that range, I estimate the equity cost of the Company's Arizona utility operations to be at the mid-point of a reasonable range of equity costs for fully-integrated electric utilities—9.50%. Applying that equity capital cost to a capital structure which is reasonable for ratemaking purposes produces an overall cost of capital of 7.43% (Exhibit_(SGH-1), Schedule 12). That overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.28 times. That level of pre-tax coverage is very similar to the 3.3 times interest coverage for APS for 2002, as reported by Moody's in its August 8, 2003 ratings report on APS (provided in response to RUCO 1-5). According to Standard & Poor's, that level of pre-tax interest coverage falls at the mid-point of a range of pre-tax interest coverages that will support a bond rating range of "A" to

"BBB" for a utility of average risk[1]. Therefore, the equity return I recommend is sufficient to support the Company's current bond rating. Therefore, the equity return I recommend fulfills the requirement of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

Q. WHY SHOULD THE COST OF CAPITAL SERVE AS A BASIS FOR THE PROPER ALLOWED RATE OF RETURN FOR A REGULATED FIRM?

A. The Supreme Court of the United States has established, as a guide to assessing an appropriate level of profitability for regulated operations, that investors in such firms are to be given an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in the unregulated sector for assuming the same degree of risk. The Bluefield and Hope cases provide the seminal decisions [Bluefield Water Works v. PSC, 262 US 679 (1923); FPC v. Hope Natural Gas Company, 320 US 591 (1944)]. These criteria were restated in the Permian Basin Area Rate Cases, 390 US 747 (1968). However, the Court also makes quite clear in Hope that regulation does not guarantee profitability and, in Permian Basin, that, while investor interests (profitability) are certainly pertinent to setting adequate rates, those interests do not exhaust the relevant considerations.

As a starting point in the rate-setting process, then, the cost of capital of a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. Since financial theory holds that investors will not provide capital for a particular investment unless that investment is expected to yield their opportunity cost of capital, the correspondence of the cost of capital with the Court's guidelines for appropriate earnings is clear.

---

[1] Standard & Poor's, Utilities & Perspectives, Utility Financial Targets Are Revised, June 21, 1999. Business position '4", pre-tax interest coverage for "A" rating = 3.3x – 4.0x, for "BBB" rating = 2.2x – 3.3x.

I. ECONOMIC ENVIRONMENT

Q. WHY IS IT IMPORTANT TO REVIEW THE ECONOMIC ENVIRONMENT IN WHICH AN EQUITY COST ESTIMATE IS MADE?

A. The cost of equity capital is an expectational, or *ex ante*, concept. In seeking to estimate the cost of equity capital of a firm, it is necessary to gauge investor expectations with regard to the relative risk and return of that firm, as well as that for the particular risk-class of investments in which that firm resides. Because this exercise is, necessarily, based on understanding and accurately assessing investor expectations, a review of the larger economic environment within which the investor makes his or her decision is most important. Investor expectations regarding the strength of the U.S. economy, the direction of interest rates and the level of inflation (factors that are determinative of capital costs) are key building blocks in the investment decision. They should be reviewed by the analyst and the regulatory body in order to assess accurately investors' required return—the cost of equity capital to the regulated firm.

Q. WHY DO YOU BELIEVE AN EQUITY RETURN IN THE RANGE OF 9.25% TO 9.75% IS REASONABLE FOR AN ELECTRIC UTILITY IN TODAY'S ECONOMIC ENVIRONMENT?

A. Although there was an upward movement in interest rate levels during 1999 and 2000, that movement reversed course during 2001 and continued a decline to much lower levels in 2002 and 2003. The overall level of fixed-income capital costs has been relatively low by historical standards for several years, and is especially low at the current time. Also, there are examples in the marketplace for equities that indicate that investor return requirements are low by historical standards.

A recent A.G. Edwards report on the gas utility industry[2] indicates that market return expectations for utility stocks are well below historical earned returns. That investor service publication reports that, for a sample of 20 large and small gas distributors, the

[2] A.G. Edwards, "Gas Utilities Quarterly Review," October 3, 2003.

median total return expectation (dividend yield plus expected growth—a DCF-type calculation) is only 8.7%.

Those data confirm that my 9.25%-9.75% equity return range for the electric utility operations under consideration here is reasonable. In addition, those data represent information to which investors are exposed in the equity marketplace for rate-regulated companies and underscore the fact that, currently, investor return requirements for that type of equity investment are low by historical standards.

Q. ARE THERE OTHER INDICATIONS THAT CAPITAL COSTS ARE AT HISTORICALLY LOW LEVELS?

A. Yes. Another indication of the reason investors are willing to buy and hold stocks that offer what seem to be "low" returns is shown in Exhibit__(SGH-1), Schedule 1, page 1, which depicts Moody's A-rated utility bond yields from 1984 through November, 2003. Page 1 of Schedule 1 shows that interest rates and capital costs remain very low relative to the interest rate levels that existed in the mid-1980s, and have continued a strong downward trend begun in 2000.

Also, page 2 of Schedule 1 (Exhibit__(SGH-1)), which presents the year-average Moody's A-rated bond yields for each year over the past 34 years (1969-2003), shows that A-rated bond yields thus far in 2003 are below the bond yield levels seen in the U.S. in the late 1960s. Also, the most recent average A-rated utility bond yield, 6.02%[3], falls well below the lower range of interest rates that have existed over the past 30 years (See Schedule 1, page 2). Simply put, a fundamental reason that the current cost of common equity capital for electric utility operations of 9.25% to 9.75% is reasonable is that fixed-income capital cost rates are lower than they have been in more than thirty years.

The above data indicate that capital costs, with the recent credit loosening by the Federal Reserve Bank (the Fed), remain at low levels and generally support the efficacy of my range of equity capital costs. However, it is important to note here that equity capital cost rates and bond yields do not move in lock-step fashion over time. In fact, the

[3] Value Line *Selection & Opinion*, most recent six weekly editions (10/24/03-11/28/03, inclusive), 20/30-year A-rated utility bond yield averages.

variability of that return differential is a fundamental reason why risk premium type analyses—which attempt to quantify the additional return over bond yields required by equity investors—are not reliable as primary indicators of equity capital cost. Therefore, it is necessary to perform an independent cost of equity capital analysis, rather than to simply "index" the cost of capital to current interest rates.

Q. PLEASE BRIEFLY DESCRIBE THE INTEREST RATE CHANGES THAT HAVE OCCURRED IN THE U.S. ECONOMY OVER THE PAST FEW YEARS AND HOW THEY IMPACT CAPITAL COST RATE EXPECTATIONS FOR THE FUTURE.

A. The substantial interest rate decline that occurred following the historically-high interest rates in the early 1980s spurred increased economic activity in the U.S. The rate of growth in the U.S. Gross Domestic Product (GDP) began to increase at a rapid rate by the end of 1987 and showed signs of continuing to gain strength. That increased economic activity, in turn, led to increased inflation expectations (a rapid rate of economic growth creates shortages in labor and materials, driving up the price of those factors of production, which ultimately results in higher prices in all sectors of the economy). The expectation of increased inflation, in turn, caused the Fed to act aggressively to slow down what was widely believed to be an overheating economy. The very sharp interest rate rise that followed in late 1987 and 1988, shown on Exhibit__(SGH-1), page 1 of Schedule 1, succeeded in damping down the economy, reducing inflationary pressures, and allowing interest rates to fall again.

Since that time, the interaction between the Federal Reserve's moves to expand or restrain the money supply and burgeoning inflation has been a primary influence in the U.S. macro-economy and the level of interest rates. Overall, as inflation has remained calm and economic activity has been moderate, interest rates have trended downward, but that general downward direction has been interrupted when investors (and/or the Fed) believed that falling interest rates would spur too-rapid economic growth. Rapid economic growth has, historically, created unwanted inflation. Investors, anticipating that higher inflation and interest rates might be the result of rapid economic expansion, have reacted to positive economic news (e.g., increasing GDP growth rates, lower unemployment) or negative inflation news (e.g., increasing commodity prices, factory capacity or labor shortages) by bidding down debt prices and driving up interest rates. That is precisely the economic situation that fueled the more recent interest rate peaks from 1994 through the 2000/2001 period (see Exhibit__(SGH-1), Schedule 1, page 1).

As shown on page 2 of Schedule 1, single-A rated utility debt yielded about 7.6%, on average, in 1999, while, in 2000, equivalently rated debt was priced to yield approximately 8.2%, on average. That cost rate increase was due, primarily, to investors' concerns regarding the continued strength of the recent U.S. economic expansion and the potential for increased inflation caused by what was perceived to be a rapid (inflationary) level of growth. However, that rapid rate of economic growth did not come to pass, and the interest rate increases engineered by the Federal Reserve in 2000 to slow down a rapidly growing economy worked a little too well, resulting in declining economic growth. Then, in response to an economy that was slowing down, the Fed elected to increase the supply of money by dramatically lowering the Federal Funds rate (the rate at which money center banks can lend funds on an overnight basis—a fundamental building block of capital costs in the U.S.). In order to revive what became a slowing economy, the Fed lowered short-term interest rates eleven times in 2001 (and again in early November 2002 as well as at mid-year 2003).

As Value Line notes in its most recent Quarterly Review regarding economic growth, inflation and the interest rate environment, the current expectation is that the Federal Reserve's recent monetary loosening will, during 2003 and 2004, begin to revive the economy. Importantly, with regard to the estimation of capital costs, inflation is expected to be moderate and interest rates will continue in the future at moderate levels preserving a favorable capital cost environment:

> **Economic Growth**: Clearly, the U.S. economic outlook is brighter than it was at the time of our last "Quarterly Economic Review." Importantly, the business revival is no longer being underpinned solely by the consumer and the federal government. The more broadly configured expansion is not also being helped by increases in capital spending and by a nascent recovery in the heretofore slumping technology sector. The projected 4% current-quarter growth rate should be sufficient, moreover, to induce many companies to start hiring again, while the recent ratcheting up in corporate

earnings should give businesses the means to support a stepped-up page in new hiring [charts omitted]. This more inclusive business expansion is also likely to support some additional increases in industrial production and factory utilization in 2004 [chart omitted].

Still, although the consumer may be ready to pass the baton to others in the coming quarters, we believe that the retail and housing sectors will continue to hold their own [charts omitted]. Exports, which have also shown improvement of late, in spite of the lack of strong growth among several of our trading partners, should provide additional support in the months ahead. The sharp decline in the value of the dollar against the currencies of other countries should continue to make corporations here more competitive on a global basis....All told, we believe that economic growth will remain just above the estimated 4% current-quarter level in 2004 and modestly below that pace over the succeeding 3 to 5 years.

Inflation: Here, the news continues to be consistently good. True, there has been a measurable increase in raw materials costs, while oil prices remain near their highs of the past two years. Of course, not all of the raw materials price hikes are being passed on to users, so actual inflation is somewhat less than the quotations for some commodities would suggest. In fact, the Federal Reserve Board, which serves as the nation's inflation watchdog, continues to believe that deflation—or actually falling prices—is a greater threat than inflation at this point. Clearly, Japan's unfortunate recent experience with deflation has caught the Fed's attention. Our sense, though, is that steadily rising costs, in such categories as medical care, housing, and education, along with stubbornly high energy prices and the likely strength of the U.S. economy going forward will prevent deflation from securing a foothold on these shores. Our projections call for consumer price inflation to remain around 2% through next year and to hold in a comfortable 2% to 2.5% range, for the most part, during the succeeding 3 to 5 years. [Chart omitted].

Interest Rates: The Federal Reserve Board, which has helped orchestrate the current business upturn with the lowest interest rates in a generation, appears to have finally finished its job. This should not imply that we thing the lead band would hesitate to provide an additional monetary boost should the current expansion falter or deflation become a reality. However, it does suggest that the Fed's next move will be to tighten the monetary reigns, most likely by mid-2004. Such a rate adjustment probably would be modest, with the bank not figuring to disturb the overall monetary stability now in place, unless future budget deficits balloon unexpectedly. Unless that happens, we think rates will hold relatively near current levels through the latter years of this

> decade, barring serous deviations from the projected rates of business growth or inflation, or a major upheaval abroad. [Chart omitted]. (The Value Line Investment Survey, *Selection & Opinion*, November 28, 2003, pp. 2618-2620.)

In that most recent Quarterly Economic Review, cited above, Value Line projects long-term Treasury bond rates will average 4.9% through 2003 and 5.5% through 2004. The recent six-week average 30-year T-bond yield is 5.2% (data from Value Line, *Selection & Opinion*, six weekly editions, October 24, through November 28, 2003). Therefore, the indicated expectation with regard to interest rates is that they are likely to will move somewhat higher in coming years but remain within a range that Value Line terms "near current levels."

Q. ARE THERE OTHER REASONS THAT COMMON EQUITY CAPITAL COSTS ARE LOWER TODAY THAN THEY HAVE BEEN IN THE PAST?

A. Yes. The recently enacted change in the Federal tax law lowered the tax rate on dividends. Under the old tax law, dividends were taxed at rates that were approximately 30%[4]; now dividends are taxed at no more than 15%. The result of that tax cut is that a greater percentage of dividends are kept by investors, and dividend-paying stocks such as utilities have become more valuable than they were before the change in the tax law. In other words, because investors can now keep more of their dividends from their utility investment, they are willing to pay more for those same stocks, resulting in a lower cost of equity capital.

The impact of the tax change on the stock prices of utilities has been recognized by investor advisory services:

> "Tax Reform Has Resulted in a Fundamental Shift in The Group's Trading Range. We estimate the reduction in dividend and capital gains taxes should result in a 10%

[4] Prior to the tax law change, federal income tax rates were 10%,15%,27%,30%,35%,or 38.6% depending upon the relevant income bracket. Under the newly passed law, the 27% drops to 25%, the 30% to 28%, the 35% to 33% and the 38.6% to 35%. Since the old 27% tax bracket applied to married couples with a combined income of no more than $47,450, it is reasonable to say that the dollar weighted dividends paid to most individual investors were in brackets of between 27% and 38.6%.

> increase in the average gas utility stock price. Prior to tax reform, the median gas utility P/E [price/earnings ratio] traded in a range of 11.5X to 14.5X. With the tax reduction, we believe the new trading range in now 12.5X to 16.0X." (A. G. Edwards, Gas Utilities Quarterly Review, October 3, 2003, p. 5)

A simple example will facilitate understanding how the tax law change has lowered the cost of equity. Assume a utility with a dividend of $0.50, a stock price of $10, and a long-term investor-expected growth rate of 5.5%. A simple DCF estimate of the cost of equity for that utility would be 10.5%, comprised of a dividend yield of 5.0% ($0.50/$10} and a growth rate of 5.5%. When the tax law changed, investors increase the price they are willing to provide for that stock by 10% (as noted in the AG Edwards report cited above), to $11 per share [10$/share x 1.10 = $11/share]. Due to that re-valuation of the stock to $11/share, the dividend yield now becomes 4.5% [$0.50/$11 = 4.545%, rounded to 4.5%]. Because the tax law does not affect the company or its utility operations, its anticipated long-term growth does not change; it remains at 5.5%. The new cost of equity, however, is 10% (4.5% dividend yield + 5.5% growth rate), roughly 50 basis points below the pre-tax change cost of equity capital. Therefore, another factor contributing to the relatively low cost of common equity capital for utilities in the current capital markets is the recent dividend tax law change.

II. CAPITAL STRUCTURE

Q. WITH WHAT CAPITAL STRUCTURE DOES APS REQUEST RATES BE SET IN THIS PROCEEDING?

A. Although Company witness Olson discusses the use of "alternative" capital structures, depending on whether or not the Pinnacle West Energy Corporation (PWEC) generation assets are allowed into rate base, the Company has filed its rate request based on one capital structure—an adjusted test-year end capital structure consisting of 50.23% common equity and 49.77% long-term debt.

However, although the Company indicates that its ratemaking capital structure is based on capital changes through June of 2003, it is not. According to the Company's published balance sheets (available in its quarterly Securities and Exchange Commission filings), APS increased its long-term debt accounts by more than $400 Million by June of 2003. According to Moody's, APS issued the additional debt in May 2003 (RUCO-1-5, Moody's Investors Service, September 2, 2003). That increased debt amount, which was related to APS's funding the debt of PWEC as allowed by this Commission, was not included in the Company's ratemaking capital structure.

Schedule D-1 in the Company's filing shows a long-term debt balance (adjusted through June 15, 2003) of $2.140 Billion. However the Company's second quarter S.E.C. Form 10-Q reports a long-term debt amount of $2.684 Billion.

Q. IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE SIMILAR TO THE MANNER IN WHICH IT HAS RECENTLY BEEN CAPITALIZED?

A. No. The Company's requested ratemaking capital structure is different from the manner in which it has been capitalized recently. Page 1 of Schedule 2 attached to my testimony shows that over the five quarters from September, 2002, through September, 2003, APS has been capitalized, on average, with 47.65% common equity, 52.23% long-term debt and 0.11% short-term debt. Also, following the Company's most recent debt issuance in May of 2003, the capital structure has averaged 45.14% common equity and 54.86% long-term debt.

Q. HOW HAS THE COMPANY'S PARENT, PINNACLE WEST, BEEN CAPITALIZED OVER THE SAME TIME PERIOD?

A. As shown on page 2 of Schedule 2, Pinnacle West's capital structure over the past five quarters has consisted of 44.53% common equity, 52.89% long-term debt and 2.58% short-term debt. Pinnacle West has been capitalized with less equity and more debt than requested by APS in its ratemaking capital structure. That capital structure inter-relationship is significant because Pinnacle West, with its unregulated competitive operations, has a higher risk profile than its regulated utility subsidiary, APS. Companies that have higher business risk are optimally capitalized with more equity and less debt than less risky companies, according to long-accepted tenets of modern corporate finance. However, in this proceeding APS, the regulated firm with *lower* operating risk, is requesting that its rates be set with a common equity ratio which is *higher* than that utilized by its operationally riskier parent. If this Commission were to utilize the Company's requested equity-heavy ratemaking capital structure, it would allow financial cross-subsidization of PWC's unregulated operations by APS's regulated ratepayers.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY FINANCIAL CROSS-SUBSIDIZATION AND WHY THIS COMMISSION SHOULD BE AWARE OF THAT ISSUE.

A. Cross-subsidization of a company's unregulated operations by its regulated operations can occur in many forms. For example, the unregulated firm could provide services to the utility at above-market rates or, conversely, the utility could provide services to its unregulated affiliates at rates below that which would prevail in an arms-length transaction. This Commission is familiar with those issues and has addressed them on many occasions.

Financial cross-subsidization occurs when the capital structure of the utility operation provides financial strength to the holding company, which, in turn, allows the parent to capitalize its unregulated operations with more debt and less equity (i.e., more cheaply) than they would otherwise be able to do. In other words, the utility (and, thereby, utility ratepayers) shoulders some of the financial risk of the unregulated affiliates by allowing the latter to be capitalized in a manner which would not prevail in a stand-alone situation.

Pinnacle West's unregulated operations are riskier operations than its regulated electric utility operations. That fact is recognized in the financial community. Regarding two factors which negatively affect Pinnacle West's financial strength, Standard & Poor's noted recently:

> "• Increasing amount of consolidated operations coming from unregulated businesses. In 2003 unregulated operations are expected to account for 15% of flow of funds from operation, although some of this is the result of expected asset sales at SunCor, and
> • Execution risk at SunCor where management has undertaken an aggressive effort to accelerate asset sales to permit SunCor to make an annual cash distribution to PWCC of between $80 million to $100 million annually during 2003

through 2005." (Standard & Poor's Ratings Direct, Pinnacle West Capital Corporation, April 8, 2003)

One way that Pinnacle West can maintain a strong financial profile and offset the increased risks of its unregulated operations, is to maintain a high common equity ratio for the capital structure of its regulated utility operation while simultaneously financing its unregulated operations with a higher percentage of debt capital than would otherwise be possible. That is the essence of financial cross-subsidization. The tangible result of that action is a common equity ratio for Pinnacle West that is below that of APS. It would not be reasonable, therefore, for this Commission to set rates for APS using the Company's requested common equity ratio which is substantially in excess of the equity capitalization of its riskier parent.

Q. IS THE COMPANY'S REQUESTED COMMON EQUITY RATIO—50%—SIMILAR TO THE AVERAGE EQUITY RATIO EXISTING IN THE ELECTRIC UTILITY INDUSTRY TODAY?

A. No. The ratemaking capitalization requested by Arizona Public Service Company for ratemaking purposes contains considerably more common equity and less debt capital than that utilized by the electric industry, on average. Because common equity capital, from a ratepayers' perspective (i.e., pre-tax), is twice as costly as debt capital, a capital structure like that requested by APS will be far more expensive that the capital structure used, on average, in the electric utility industry.

As shown on page 3 of Schedule 2, the average common equity ratio of the electric industry, as reported in the November 2003 edition of C.A. Turner's Utility Reports is 40%. For investment grade electrics (i.e., those that have bond ratings of "BBB" or above), the average common equity ratio is also 40%. C.A. Turner's also indicates that for combination utilities—electric and gas—the average common equity ratio is 37% of total capital. For investment grade combination utilities the average common equity ratio is slightly higher—39%.

Page 4 of Schedule 2 shows that the electric companies which were selected by Company witness Olson as similar in risk to APS have a median common equity ratio of

38%. In addition, the median common equity ratio of the electric companies I selected as similar in risk to APS have a median common equity ratio of 39.50%.

The evidence available in the marketplace as well as the similar-risk sample companies selected by Dr. Olson and myself, indicate that the capital structure requested for ratemaking purposes by APS contains a level of equity capital far above that used, on average, in the electric utility industry. Those data show that APS requests that its rates be set with a capital structure which is far more expensive capital structure than that which exists, on average, for electric utility operations.

Q. DO YOU BELIEVE IT IS NECESSARY FOR THE COMMISSION TO ALLOW THE PWEC GENERATION ASSETS INTO APS 's REGULATED RATE BASE IN ORDER TO SET RATES FOR THIS COMPANY USING A CAPITAL STRUCTURE CONSISTING OF APPROXIMATELY 45% COMMON EQUITY AND 55% DEBT?

A. No, for several reasons. First, the Company's current (i.e., known-and-measurable) capital structure is comprised of approximately 45% equity and 55% debt, not the 50%/50% capitalization on which it rate request is based. Regardless of whether or not the debt in the capital structure finances rate base, that debt is the financial responsibility of APS, and, in turn, it's ratepayers. APS's income stream will be encumbered by that debt and the Company's ratepayers will be called on to provide the interest costs associated with that debt.

Second, the Company clearly had the capability to assume the additional leverage without affecting its financial risk, as noted by Standard & Poor's: "The ratings on APS reflect the company's financial condition, which is sufficiently resilient to withstand the impact of the new debt at the current rating level." (S&P Ratings Direct, May 7, 2003, RUCO-1-5). Therefore, the Company had the ability to be financed more cost-effectively (i.e., with more debt and less equity) than the capital structure with which it requests its rates be set in the instant proceeding, and that opportunity should have been utilized to finance its Arizona jurisdictional utility plant, regardless of the status of the PWEC assets.

Third, ignoring the actual amount of debt on APS's balance sheet (i.e., utilizing a 50% equity/50% debt capital structure for ratesetting purposes) would require the

Company's Arizona ratepayers to provide an equity return as well as the taxes that must be paid on that return instead of a debt return on that portion of whatever rate base is approved in this proceeding. From a ratepayer perspective common equity is roughly twice as expensive as debt. Therefore, effectively substituting equity capital for debt capital in the ratemaking capital structure would cause the capital costs included in rates to overstate the Company actual capital costs, leading to rates which are not cost-based.

Fourth, the Company's requested capital structure is substantially different from the manner in which the electric industry is capitalized. APS requests its rates be set in this case using a 50% common equity ratio, while the electric utility industry, on average is capitalized with about 40% common equity.

Fifth, the Company's current actual capital structure (containing 45% common equity) is still more equity-rich that the industry generally, and more equity rich than the similar-risk sample groups chosen by Company witness Olson and myself to estimate APS's cost of equity capital. In that regard, a ratemaking capital structure based on APS's current actual capital structure would afford the Company lower financial risk than that realized by the electric industry generally and the similar-risk sample groups used to estimate the Company's cost of equity capital.

Q. HAS THIS COMMISSION SET RATES FOR COMPANIES UNDER ITS PURVIEW USING CAPITAL STRUCTURES THAT ARE DIFFERENT THAT THE ACTUAL, BOOKED CAPITAL STRUCTURE?

A. Yes. For many years this Commission has set rates for the Arizona jurisdictional operations of Southwest Gas using a hypothetical capital structure containing a different amount of common equity than the company actually carried on its books. Setting rates on that company's actual, booked capital structure, which contained a low common equity ratio, could have had the effect of exacerbating the company's financial risk. Increased financial risk could have lead to further financial difficulty for Southwest Gas and, ultimately, a higher overall cost of capital. Therefore, the Commission elected to set rates using a common equity ratio lower than other similar-risk firms but above that company's actual, booked common equity ratio.

This Commission utilized the same logic with Tucson Electric Power when that company was emerging from bankruptcy. It set rates using a nominal or hypothetical capital structure in order to preserve that company's financial strength during its recovery from Chapter 11 proceedings.

In the instant proceeding, as in the cases cited above, the Commission is faced with an applicant utility which has an actual capital structure which is not cost-effective. The only difference in APS's case is that the Company is over-capitalized, i.e., is requesting that its rates be set on a capital structure that is too expensive to be commensurate with the risk of its operations, rather than under-capitalized. Given this Commission's prior position on the use of ratemaking capital structures, an even-handed approach in this proceeding would be to set rates for APS using a more cost-effective yet financially safe capital structure—one with less common equity capital than that requested by APS. Therefore, the use of a hypothetical capital structure containing 45% common equity and 55% debt is reasonable from the standpoints of financial economy and financial strength, and is consistent with this Commission's prior position regarding the use of ratemaking capital structures different from the actual booked capital structure of the applicant utility.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. For the reasons outlined above, the Company's rates should be set using a capital structure with approximately 45% common equity and 55% debt. Regardless of the disposition of the PWEC assets, the Commission should reject the Company's requested 50% equity/50% debt capital structure and set rates using a more cost-effective but financially safe capital structure consisting of 45% common equity and 55% debt.

Q. ARE THERE OTHER CAPITAL STRUCTURE ISSUES WHICH YOU BELIEVE SHOULD BE BROUGHT TO THE ATTENTION OF THIS COMMISSION?

A. Yes. As I noted in my discussion of the economy, debt cost rates are currently at historic lows. Short-term debt costs are at especially low levels. For example, Pinnacle West was able to borrow $50 Million in August 2003 at a cost rate of only 1.43%. That is, indeed, very low cost capital. Given that the object of any financial manager is to finance the operations of the firm in the most cost-effective, fiscally sound manner possible, the use of moderate amounts of very low-cost short term debt should be part of that strategy in today's capital markets.

Q. IS IT REASONABLE TO INCLUDE SHORT-TERM DEBT IN A RATEMAKING CAPITAL STRUCTURE?

A. Yes. First, it is not possible to specifically identify the source of monies spent on utility construction projects, or any other corporate expense, for that matter. Dollars enter the corporate treasury from many sources—retained earnings, common equity infusions, dividend reinvestment, as well as long-term and short-term debt issuances. However, once those dollars are in the corporate treasury they are indistinguishable from one another. For that reason it is not possible, when monies are paid out of the treasury (for office supplies, transformers or anything else), to discern precisely where those dollars come from. Therefore, it is not possible to reliably claim that construction is funded *only* by short-term debt (as the Company does in its filing, e.g., Schedule D-1). The only logical assumption is that construction, as indeed are all corporate expenses, is funded by a variety of investor-supplied sources as well as internally generated funds.

Second, short-term debt is investor-supplied capital and is a quantifiable part of the capital mix utilized by utility operations. The use of an average level of short-term debt in a ratemaking capital structure, then, recognizes the capital mix employed by utility management and more accurately represents the Company's actual cost of capital. Moreover, it simply does not make good financial sense to avoid use of the cheapest form of capital available.

Third, bond rating agencies, in calculating the debt-to-capital and interest coverage ratios include short-term debt and the interest on short-term debt, respectively, in those calculations. It is reasonable to assume, then, that those data are important in estimating the financial health of a firm and are important to investors. Although the level of short-term debt fluctuates from time to time, it has been my experience that short-term debt is a permanent part of utility capital structures over the long term and should be considered for ratemaking purposes.

Fourth, because short-term debt carries a lower cost rate than other forms of capital, failure to consider the Company's use of that type of capital would result in an overstatement of the Company's overall cost of capital. The Company's requested overall return, which does not account for the amount of short-term debt expected to be used by the Company, is flawed in that manner, i.e., it overstates the Company's actual overall cost of capital.

Q. HAVE YOU EXAMINED THE COMPANY'S AND PINNACLE WEST'S USE OF SHORT-TERM DEBT?

A. Yes. Page 5 of Schedule 2 shows the average daily balances of Short-term debt for both Pinnacle West and APS from January 2001 through the most recent month available—August 2003. For Pinnacle West, over that entire historical time period the monthly average amount of short-term debt outstanding was approximately $200 Million. That level declined to an average of about $150 Million in 2003.

The historical short-term debt usage data for APS reveals an unusual pattern which appears to be designed to coincide with the current rate case proceeding. The Company apparently elected to stop using short-term debt at the end of 2002—the end of the historical test year. In fact, the Company reports a $0 balance of short-term debt on its December 31, 2002 balance sheet but shows an average daily balance of $13 Million of short-term debt for December 2003 in its response to RUCO-1-6. That means, simply, that APS utilized short-term debt in December 2002, but elected to eliminate that form of financing on the last day of 2002—the end of the test year in this proceeding. Pinnacle West continues to finance its operations with short-term debt, but APS appears to have ceased using that most inexpensive form of capital in anticipation of this rate proceeding[5].

It appears that the Company is purposely eliminating short-term debt from its investor-supplied capital mix in order to affect the outcome of this rate proceeding. The

[5] Because short-term debt appears on the balance sheet of Pinnacle West, but not on the balance sheet of its regulated subsidiary—APS, we must assume that Pinnacle West is continuing to finance its unregulated operations with short-term debt.

company can "game" the regulatory process and effectively raise the equity return it is allowed in this rate proceeding by convincing this Commission to omit short-term debt from the ratemaking capital structure and then, following the rate case, begin again to utilize short-term debt in its capital mix. The use of short-term debt will cause the Company's overall cost of capital to fall below that determined absent consideration of short-term debt, and the residual will impact the bottom line in the form of higher net income and a higher return on equity than allowed.

In the current interest rate environment, in my view, it is not reasonable to finance utility operations without the use of any short-term debt. To do so would forego an opportunity to more cost-effectively capitalize utility operations. Therefore, regardless of the pattern of the Company's use of short-term debt, I believe it is reasonable and prudent to include a modest amount of short-term debt in the ratemaking capital structure.

Q. HOW HAVE YOU DETERMINED YOUR RECOMMENDED RATEMAKING CAPITAL STRUCTURE?

A. Page 1 of Schedule 2 shows that over the most recent two quarters, APS's total capital has averaged $4.836 Billion. Of that amount, 45.14% was common equity and 54.86% of that is debt. In adjusting that debt amount to include short-term debt on a pro-forma basis, it is reasonable to assume that $50 Million of that total debt amount on a ratemaking basis will be short-term debt. The Company monthly-average amount of short term debt from January 2001 through August 2003 was $48.5 Million, even with zero balances in 2003.

Page 6 of Schedule 2 shows that, with that adjustment to the Company's actual average debt balance, the pro-forma ratemaking capital structure consists of 45.14% common equity, 58.83% long-term debt and 1.03% short-term debt. The cost rate of long-term debt at June 30, 2003, 5.77%, is provided by the Company in response to RUCO 1-2. The cost of short-term debt, 3.0%, is a forward-looking estimate which accounts for the expected increase in short-term debt cost rates. The most recent available cost rate of long-term debt available to Pinnacle West is 1.43% (see Schedule 2, page 5).

Q. DOES THIS CONCLUDE YOUR DISCUSSION OF CAPITAL STRUCTURE?

A. Yes, it does.

III. METHODS OF EQUITY COST EVALUATION

DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW (DCF) MODEL YOU USED TO ARRIVE AT AN ESTIMATE OF THE COST RATE OF COMMON EQUITY CAPITAL FOR THE COMPANY IN THIS PROCEEDING.

A. The DCF model relies on the equivalence of the market price of the stock (P) with the present value of the cash flows investors expect from the stock, providing the discount rate equals the cost of capital. The total return to the investor, which equals the required return according to this theory, is the sum of the dividend yield and the expected growth rate in the dividend.

The theory is represented by the equation,

$$k = D/P + g, \qquad (1)$$

where "k" is the equity capitalization rate (cost of equity, required return), "D/P" is the dividend yield (dividend divided by the stock price) and "g" is the expected sustainable growth rate.

Q. WHAT GROWTH RATE (g) DID YOU ADOPT IN DEVELOPING YOUR DCF COST OF COMMON EQUITY FOR THE ELECTRIC UTILITIES?

A. The growth rate variable in the traditional DCF model is quantified theoretically as the dividend growth rate investors expect to continue into the indefinite future. The DCF model is actually derived by 1) considering the dividend a growing perpetuity, that is, a payment to the stockholder which grows at a constant rate indefinitely, and 2) calculating the present value (the current stock price) of that perpetuity. The model also assumes that the company whose equity cost is to be measured exists in a steady state environment, i.e., the payout ratio and the expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever. As with all mathematical models of real-world phenomena, the DCF theory does not exactly "track" reality. Payout ratios and expected equity returns do change over time. Therefore, in order to properly apply the DCF model to any real-world situation and, in this case, to find the long-term sustainable growth rate called for in the DCF theory, it is essential to understand the determinants of long-run expected dividend growth.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THE DETERMINANTS OF LONG-RUN EXPECTED DIVIDEND GROWTH?

A. Yes, in Appendix B, I provide an example of the determinants of a sustainable growth rate on which to base a reliable DCF estimate. In addition, in Appendix B, I show how reliance on earnings or dividend growth rates alone, absent an examination of the underlying determinants of long-run dividend growth, can produce inaccurate DCF results.

Q. DID YOU USE A SUSTAINABLE GROWTH RATE APPROACH TO DEVELOP AN ESTIMATE OF THE EXPECTED GROWTH RATE FOR THE DCF MODEL?

A. Yes. I have calculated both the historical and projected sustainable growth rate for a sample of electric utility firms with similar-risk operations. To supplement the sustainable growth rate analysis, I have also analyzed published data regarding both historical and projected growth rates in earnings, dividends, and book value for all the companies under study.

Q. WHY HAVE YOU USED THE TECHNIQUE OF ANALYZING THE MARKET DATA OF SEVERAL COMPANIES?

A. I have used the "similar sample group" approach to cost of capital analysis because it yields a more accurate determination of the cost of equity capital than does the analysis of the data of one individual company. Any form of analysis, in which the result is an estimate, such as growth in the DCF model, is subject to measurement error, i.e., error induced by the measurement of a particular parameter or by variations in the estimate of the technique chosen. When the technique is applied to only one observation (e.g., estimating the DCF growth rate for a single company) the estimate is referred to, statistically, as having "zero degrees of freedom." This means, simply, that there is no way of knowing if any observed change in the growth rate estimate is due to measurement error or to an actual change in the cost of capital. The degrees of freedom can be increased and exposure to measurement error reduced by applying any given estimation technique to a sample of companies rather than one single company. Therefore, by analyzing a group of firms with similar characteristics, the estimated value (the growth rate and the resultant cost of capital) is more likely to equal the "true" value for that type of operation.

Q. HOW WERE THE FIRMS SELECTED FOR YOUR ANALYSIS?

A. In selecting a sample of electric firms to analyze, I screened all the electric utility firms followed by Value Line. I selected companies from that group that had a continuous financial history and had at least 70% of operating revenues generated by electric utility operations. In addition, I eliminated companies that were in the process of merging or being acquired <u>and</u> had realized an upward stock price shift due to that activity or companies that had omitted dividends. Also, the companies in the selected sample had to own generation assets and have a bond rating ranging from "BBB" to "A+". The sample group selection screening process I utilized in shown in detail on Schedule 3 attached to this testimony.

Twelve electric utilities passed the screening process, including Pinnacle West, APS' parent. The companies included in the sample group are: Central Vermont Public Service (CV), Energy East Corp. (EAS), FirstEnergy Corp. (FE), Southern Company (SO), Ameren Corp. (AEE), Cleco Corp. (CNL), DPL, Inc. (DPL), Empire District Electric (EDE), Entergy Corp. (ETR), Great Plains Energy (GXP), Hawaiian Electric (HE), and Pinnacle West Capital Corp. (PNW). [Note: In the Schedules accompanying this testimony, the sample group companies are referred to by their stock ticker symbols, designated above in parentheses.]

Q. HOW HAVE YOU CALCULATED THE DCF GROWTH RATES FOR THE SAMPLE OF COMPARABLE COMPANIES?

A. Schedule 4 pages 1 through 4, shows the retention ratios, equity returns, sustainable growth rates, book values per share and number of shares outstanding for the comparable companies for the past five years. Also included in the information presented in Schedule 4, are Value Line's projected 2003, 2004 and 2006-2008 values for equity return, retention ratio, book value growth rates and number of shares outstanding.

In evaluating these data, I first calculate the five-year average sustainable growth rate, which is the product of the earned return on equity (r) and the ratio of earnings retained within the firm (b). For example, Schedule 4, page 2, shows that the five-year average sustainable growth rate for Southern Company (SO) is 3.37%. The simple five-year average sustainable growth value is used as a benchmark against which I measure the company's most recent growth rate trends. Recent growth rate trends are more investor-influencing than are simple historical averages. Continuing to focus on SO, we see that sustainable growth in 2002 was about 4%—above the average growth for the five-year period, indicating an increasing trend in growth. By the 2006-2008 period, Value Line projects SO's sustainable growth will reach a level above the recent five-year average—about 5%. These data would indicate that investors expect SO to grow at a rate in the future above the growth rate that has existed, on average, over the past five years[6].

It is important to note that, while the five-year projections are given consideration in estimating a proper growth rate because they are available to and are used by investors, they are not given sole consideration. Without reviewing all the growth rate data available to investors, both projected and historic, sole reliance on projected information may be misleading. Value Line readily acknowledges to its subscribers the subjectivity necessarily present in estimates of the future:

> We have greater confidence in our year-ahead ranking system, which is based on proven price and earnings momentum, than in 3- to 5-year projections. (Value Line Investment Survey, Selection and Opinion, June 7, 1991, p.854).

[6] I have included the details of my growth rate analyses for SO as an example of the methodology I use in determining the DCF growth rate for each company in the industry sample. A description of the growth rate analyses of each of the companies included in my sample group is set out in Appendix C. Schedule 5, page 1, of Exhibit_(SGH-1) attached to this testimony shows the internal, external and resultant overall growth rates for all the companies analyzed.

Another factor to consider is that SO's book value growth is expected to increase substantially, increasing at a 5% level over the next five years, after decreasing at a 1% rate historically (Southern Company divested its unregulated generation operation two years ago). Also, as shown on Schedule 5, page 2, Southern Company's dividend growth rate, which was only 1.5% historically, is expected to increase to 3% in the future. While this confirms that future growth is likely to be greater than historical growth, the projected dividend growth is below the sustainable growth rate projections. Earnings growth rate data available from Value Line indicate that investors can expect a higher growth rate in the future (6.5%) than has existed over the past five years (2.0%). However, Zack's and Thomson Financial (investor advisory services that poll institutional analysts for growth earnings rate projections) project lower earnings growth rate for SO over the next five years —4.5% and 5.0%, respectively.

SO's projected sustainable growth, book value, dividend and projected earnings growth indicates that investors can expect higher growth than has occurred, on average, in the past. Those projections are moderated somewhat by an expectation of dividend growth below the level of earnings growth projections. A long-term sustainable growth rate of 5.0% is a reasonable expectation for SO.

Q. IS THE INTERNAL (b x r) GROWTH RATE THE FINAL GROWTH RATE YOU USE IN YOUR DCF ANALYSIS?

A. No. An investor's sustainable growth rate analysis does not end upon the determination of an internal growth rate from earnings retention. Investor expectations regarding growth from external sources (sales of stock) must also be considered and examined. For SO, page 2 of Schedule 4 shows that the number of outstanding shares increased at about a 0.6% rate over the most recent five-year period. Value Line expects the number of shares outstanding to increase more rapidly through the 2006-2008 period, bringing the share growth rate to about a 1.5% rate by that time. An expectation of annual share growth of 1.25% is reasonable for this company.

Because a goal of regulation, in duplicating the strictures of the competitive marketplace, is to allow a utility to recover no more than its cost of capital, it is reasonable to assume that the market price/book value ratio would, over the long-term horizon of the DCF model, have a tendency toward unity. However, the market price/book value ratio is unlikely to reach 1.0 overnight and, on average, utilities will continue to issue stock at prices above book value. In addition, Professor Myron Gordon, often referenced as the "father" of DCF in regulation, indicates that the DCF can overstate the cost of common equity capital when allowed returns exceed the cost of capital[7] (i.e., when market prices are substantially above book value as they are currently). Finally, although I have selected electric utility firms for analysis which derive the majority of their revenues from electric utility operations, those firms are not "pure play" utilities—they do have some other operations. Those other operations, therefore, are likely to have an upward impact on the market price and the market-to-book ratio of those companies.

I believe, therefore, that a reasonable estimate of investors' expectations for utility price/book ratios is that it will range between current levels and 1.0. I have used the average as an estimate of investors' expectations for the future. For our example company, Southern Company, the result of combining expected internal (b x r = 5.00%) and external growth rates (1.25%) yields an investor-expected long-term growth rate of 5.81% (see Exhibit__(SGH-1), Schedule 5, page 1 of 2).

Q. HAVE YOU CHECKED THE REASONABLENESS OF YOUR GROWTH RATE ESTIMATES AGAINST OTHER, PUBLICLY AVAILABLE, GROWTH RATE DATA?

A. Yes. Page 2 of Schedule 5 shows the results of my DCF sustainable growth rate analysis as well as 5-year historic and projected earnings, dividends and book value growth rates from Value Line, earnings growth rate projections from Zack's (and Thomson Financial), the average of Value Line and Zack's growth rates and the 5-year historical compound growth rates for earnings, dividends and book value for each company under study.

For the electric utility sample group, Schedule 5, page 2, shows that my DCF growth rate estimate for those companies is 4.79%. That long-term growth rate estimate is

[7] Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp. 9, 10.

higher than Value Line's average projected earnings, dividend and book value growth rate (3.33%) and much higher than the historical average of those same parameters (2.17%). In addition, my DCF growth rate estimate for the electric companies is also somewhat lower than Zack's projected earnings growth rate estimate (5.13%), but above both Value Line's projected growth rate estimate (3.63%) and Thomson Financial's projected growth rate (4.08%). My DCF growth rates for these companies may be conservative on the high side, when compared to available published information.

Q. DOES THIS CONCLUDE THE GROWTH RATE PORTION OF YOUR DCF ANALYSIS?

A. Yes, it does.

Q. HOW HAVE YOU CALCULATED THE DIVIDEND YIELDS?

A. I have estimated the next quarterly dividend payment of each firm analyzed and annualized them for use in determining the dividend yield. If the quarterly dividend of any company were expected to be raised in the quarter following that in which the most recent dividend was declared, I increased the current quarterly dividend by (1+g). For the electric companies in the sample group, a dividend adjustment was unnecessary for most of the companies under study because they either recently raised their dividend or were not projected to raise the dividend in 2004. A dividend adjustment was required for two companies in the sample, Central Vermont Public Service (CV), and Energy East (EAS).

The next quarter annualized dividends were divided by a recent daily closing average stock price to obtain the DCF dividend yields. I use the most recent six-week period to determine an average stock price in a DCF cost of equity determination because I believe that period of time is long enough to avoid daily fluctuations and recent enough so that the stock price captured during the study period is representative of current investor expectations.

Schedule 6 indicates that the average dividend yield for the sample group of electric utility companies is 4.89%. It is interesting to note that Value Line's most recent year-ahead dividend yield projection for the companies in my sample group averaged 4.92%—very similar to the dividend yield I use in my analysis (Value Line, *Summary & Index,* November 28, 2003). That indicates that the dividend yield used in my DCF analysis is reasonable, and is representative of investor expectations.

Q. WHAT IS YOUR COST OF EQUITY CAPITAL ESTIMATE FOR THE ELECTRIC UTILITY COMPANIES, UTILIZING THE DCF MODEL?

A. Schedule 7 shows that the average DCF cost of equity capital for the entire group of electric utilities studied is 9.69%.

CORROBORATIVE EQUITY COST ESTIMATION METHODS

Q. IN ADDITION TO THE DCF, WHAT OTHER METHODS HAVE YOU USED TO ESTIMATE THE COST OF EQUITY CAPITAL FOR ARIZONA PUBLIC SERVICE COMPANY?

A. To support and temper the results of my DCF analysis, I have used three additional econometric methods to estimate the cost of equity capital for a group of firms similar in investment risk to APS. The three methodologies are: 1) the Capital Asset Pricing Model (CAPM), 2) the Modified Earnings-Price Ratio (MEPR) analysis, and 3) the Market-to-Book Ratio (MTB) analysis. The similar risk sample group of firms analyzed with these three methods is the same as that selected for the DCF analysis, discussed previously. The theoretical details of each of those analyses is contained in Appendix D, attached to this testimony. The actual calculations and data supporting the results of each of these models is shown in the attached Schedules.

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis, which indicates a cost of capital for electric companies ranging from 8.33% to 9.47%. Schedule 10 shows the data and calculations regarding the Modified Earnings Price Ratio (MEPR) analysis, which indicates a current cost of equity capital for companies like APS ranging from 9.16% to 9.49%. Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital of 9.59% (near-term) to 9.30% (long-term).

SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table on the following page.

METHOD	COST OF EQUITY
DCF	9.69%
CAPM	8.33%/9.47%
MEPR	9.16%/9.49%
MTB	9.59%/9.30%

The DCF result noted above, which is my primary indication of the cost of equity capital, is 9.69%. Averaging the lowest and the highest results of the corroborative analyses (CAPM, MEPR, and MTB) produces an equity cost rate range of 8.93% to 9.52%—a range that is entirely below the DCF result. In fact, only the upper end of the range of corroborative results are near the DCF result; all of the other corroborative analyses indicate that my DCF results may overstate the actual cost of common equity of electric utilities. Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company facing similar risks as that group of electric utility companies ranges from 9.25% to 9.75%. Within that range, a reasonable point-estimate for the cost of common equity capital for APS would be a the mid-point of that range, or 9.50%.

Q. DOES YOUR EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, there is no information in the evidence presented by the Company in this case that indicates that it anticipates a public stock offering. Absent such an offering, the Company will not incur flotation costs going forward and should not be reimbursed for a cost it will not incur. Moreover, any attempt to collect equity financing costs incurred in prior periods would amount to retro-active ratemaking.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. For example, as Company witness Olson noted in his Direct Testimony in this case:

> "The market-to-book ratio should be set high enough to permit equity financing with net proceeds equal to or in excess of book [value] under most market conditions, otherwise dilution will take place." (Olson Direct, p. 25, ll. 4-6)

In the current market environment for electric utility common stock, Pinnacle West stock is selling at roughly a 20% premium to its book value. Therefore, even if we assume as Dr. Olson does, that 3% of the stock price is an out-of-pocket cost for the Company, every time a new share of Pinnacle West stock is sold, all shareholders realize an *increase* in the per share book value of their investment. No dilution occurs, even without any flotation cost allowance.

For example, assume that Pinnacle West had one share of stock outstanding with a market price of $1.20 and a book value of $1.00. Assume also the parent company issued another share of stock at the current market price of $1.20 and actually paid out-of-pocket flotation costs of 4¢ (approximating Olson's average 3% flotation cost estimate). The monies received from the stock issuance, $1.16 (the $1.20 market price less the 4¢ flotation cost), would be added to the Company's common equity. That $1.16 added to the original $1.00 of common equity on the books, indicates a total common equity balance for Pinnacle West after the stock issuance of $2.16. That book balance of common equity divided by the two outstanding shares produces a per share book value of $1.08 [$2.16 ÷ 2]. In other words, the stockholders' investment value is increased when new stock is issued, not decreased, because the amount that market value exceeds book value is substantially more than any anticipated flotation costs. Therefore, there is no need to "compensate" stockholders for a hypothetical dilution of book value that will not exist.

Third, assuming *arguendo* the need for an issuance expense adjustment to the cost of equity, the majority of the issuance expenses incurred in any public offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

Moreover, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that knowledge, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[8]. There are other transaction costs which, when properly considered,

[8] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs which, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs which lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's ELECTRIC UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.50%?

A. Schedule 12 attached to my testimony shows that an equity return of 9.50%, operating through an appropriate ratemaking capital structure and embedded capital cost rates, produces an overall return of 7.43% for APS. Schedule 12 also shows that an 7.43% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.28 times. According to Moody's Investors Service (ratings report on APS, August 8, 2003), APS's pre-tax interest coverage in 2002 was 3.3 times. Because the Company was able to maintain it's bond rating over the past year its is reasonable to believe that the equity return I recommend is sufficient to support APS's current bond rating. Also, according to Standard & Poor's published bond rating benchmarks the pre-tax interest coverage afforded by the equity return I recommend will support a bond rating in the range of "A" to "BBB", which brackets the Company's current bond rating. Therefore, the equity return I recommend fulfills the legal requirement of <u>Hope</u> and <u>Bluefield</u> of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

IV. COMPANY COST OF CAPITAL TESTIMONY

Q. WHAT METHODS HAS COMPANY WITNESS OLSON USED TO DETERMINE EQUITY CAPITAL COSTS IN THIS PROCEEDING?

A. Company witness Olson testifies that he based his recommendation on the results of his DCF analysis, which he checks with a risk premium analysis. The Company witness' DCF methodology is flawed and produces results which are overstated due to his use of stale stock price and growth rate data. In addition, his sole reliance on projected earnings growth rates causes his DCF results to be overstated. Had the Company witness relied on other growth rate data available to investors, his results would approximate those I present in my testimony.

Although Dr. Olson's DCF produces overstated results, they are far more reasonable results than his Risk Premium analysis, which significantly overstates the Company's cost of equity capital. As I discuss in more detail below, Dr. Olson's Risk Premium analysis does not serve as a reasonable check of his DCF analysis because 1) it is based on very long-term return data not necessarily representative of current risk/return relationships and 2) it is based on a measure of return appropriate for all stocks, not utility stocks, which are considerably less risky than the broad market measure used by the Company witness.

I will discuss the infirmities in Dr. Olson's DCF analysis initially, and then discuss the witness' Risk Premium analysis.

Q. WHAT ARE YOUR COMMENTS REGARDING COMPANY WITNESS OLSON'S DCF ANALYSIS?

A. Although he does not show the results in the attachments to his testimony, Dr. Olson's DCF results range from 9.89% to 14.67% for his sample group of electric companies, and 10.05% for Pinnacle West. Dr. Olson's DCF result for his sample group is overstated because 1) he relied on results for one of his sample companies that is a statistical outlier,

2) he used stock price and growth rate data which are not representative of current capital costs, 3) he increased the divided for next period growth whether or not such an adjustment was warranted and 4) he relied only on projected per share earnings growth rate data to determine the long-term sustainable growth called for in DCF theory, even though he testifies that investors use other measures of growth.

Q. WHICH DCF RESULT OBTAINED BY DR, OLSON IS A STATISTICAL OUTLIER?

A. Dr. Olson's Attachments CEO-6 and CEO-7 show the dividend yield and growth rate for each of his sample companies. Those data indicate the DCF results for his sample group of companies shown in Table I below.

TABLE I.

DR. OLSON'S DCF ANALYSIS RESULTS

COMPANY	DIVIDEND YIELD	GROWTH RATE	DCF RESULT
CINergy	5.39%	4.50%	9.89%
IDACORP	7.67%	7.00%	**14.67%**
OGE Energy Corp.	6.95%	3.50%	10.45%
PPL Corp.	4.18%	5.90%	10.08%
Progress Energy	5.24%	5.00%	10.24%
Public Serv. Ent.	6.08%	5.00%	11.08%
		Average without IDACORP	10.35%
		Standard Deviation without IDACORP	0.46%
		Avg + 3 St. Deviation Units	11.72%

Table I shows that the DCF result for one of Dr. Olson's sample companies, IDACORP, is significantly different from the average of the other companies. The average simple DCF cost of equity of the other companies in Dr. Olson's sample group is 10.35%. The standard deviation of those average results (i.e., without IDACORP) is 0.46%. Adding three times that standard deviation (3 x 0.46%) to the average DCF result of the other companies indicates that the upper bound of a statistically reliable DCF estimate would be 11.72%[9].

[9] Assuming a normally distributed sample, 99.9% of the observations fall within three standard deviations of the mean or average of the sample.

Obviously, Dr. Olson's DCF result for IDACORP falls well outside of that range of reasonableness (termed a statistical outlier) and should not be relied on as an indicator of the cost of equity capital of APS in this proceeding. As shown in Table I, eliminating IDACORP from his sample of firms causes Dr. Olson's average DCF equity cost estimate to fall to 10.35%. However, as I show below, that estimate is stale and newer information indicates that the cost of equity of Dr. Olson's sample group is considerably lower.

Q. YOU MENTIONED PREVIOUSLY THAT DR. OLSON'S DCF DATA ARE STALE, AND SERVE TO OVERSTATE THE CURRENT COST OF EQUITY CAPITAL, EVEN USING HIS METHODOLOGY. CAN YOU PLEASE EXPLAIN YOUR COMMENTS?

A. Yes. As shown in Table II, below, using Dr. Olson's DCF methodology and current data the overall average DCF cost of capital for his sample group is 9.15%, and 9.80% for Pinnacle West Capital producing an overall average of 9.24%. That result is roughly 100 basis points below his DCF equity cost range excluding IDACORP shown in Table I, above, and 200 basis points below the low end of his equity return recommendation in this proceeding (11.25%).

TABLE II.

DR. OLSON'S DCF ANALYSIS, UPDATED

COMPANY	DIVIDEND YIELD*	GROWTH RATE	DCF RESULT
CINergy	5.20%	4.00%	9.20%
IDACORP	4.20%	5.00%	9.20%
OGE Energy	5.70%	3.00%	8.70%
PPL Corp.	4.00%	5.00%	9.00%
Progress Energy	5.40%	4.00%	9.40%
P.S. Ent. Group	5.40%	4.00%	9.40%
AVERAGE	4.98%	4.17%	**9.15%**
Pinnacle West	4.80%	5.00%	9.80%
OVERALL AVERAGE DCF RESULT =			**9.24%**

* Value Line Summary & Index 11/28/03, proj. year-ahead yield.
* Projected 5-year earnings growth, Thomson Financial (12/9/03).

Value Line's current year-ahead divided yield projections for those companies[10] (which encompasses expected dividend increases and current stock prices) average 4.98%—about 100 basis points less than Dr. Olson's reported yield for those same companies (5.92%). The current projected earnings growth rates for his sample companies is 4.17%, well below the 5.0% to 5.5% he uses in his original DCF analysis. Therefore, a more current cost of equity result, using Dr. Olson's own DCF analysis would approximate 9.25%, not the 11.07 to 11.58% he reports at page 22 of his Direct Testimony in this proceeding.

Q. WHAT DCF GROWTH RATE METHODOLOGY DID WITNESS OLSON USE?

A. As shown on Schedule CEO-7 attached to Dr. Olson's testimony, the only growth rate data he relied on in determining his DCF growth rate was projected earnings growth. Dr. Olson elects to adopt that methodology in this proceeding even though he testifies at page 18 of his testimony that in addition to stock price data, investors are likely to have access to "past and present dividends, past and present earnings." Moreover, he states at line 20 on page 18 of his Direct, "[h]owever, it is not reasonable to expect that past trends are ignored" by investors. I agree. Dr. Olson's DCF analysis which totally ignores "past trends" does not provide a reasonable basis for estimating the current cost of equity capital.

Q. HAS DR. OLSON CONSISTENTLY USED A DCF GROWTH RATE METHODOLOGY THAT RELIES ONLY ON PROJECTED EARNINGS PER SHARE GROWTH?

A. No. Dr. Olson and I have testified in many rate cases together over the years and only recently has he begun to rely solely on projected earnings growth rate data in determining his DCF growth rate. In prior proceeding in which he and I have been involved (e.g., Montana Public Service Commission Docket No. D95.9.128, Montana Power Company), Dr. Olson has relied on 10-year and 5-year historical growth rates in earnings, dividends and book value, sustainable ('b x r") growth as well as projected earnings growth rates.

As shown in my Schedule 4, page 2 of 2, the historical and projected growth in dividends and book value are below the projected earnings growth rates for electric utilities.

---

[10]The Value Line Investment Survey, *Summary & Index*, November 28, 2003.

It is reasonable to assume, therefore, that had Dr. Olson considered those data in addition to the projected earnings growth of his sample group (as he has done in the past) his DCF result would have been lower than that which he presents in his testimony in this proceeding and lower even than the DCF shown in Table II, above.

Q. WHAT ARE YOUR COMMENTS ON THE EXCLUSIVE USE OF PROJECTED EARNINGS GROWTH RATES IN A DCF ESTIMATE OF THE COST OF EQUITY CAPITAL?

A. In my view, earnings growth rate projections are widely available, are used by investors and therefore deserve consideration in an informed, accurate assessment of the investor expected growth rate to be included in a DCF model. I do not believe, however, that projected earnings growth rates should be used as the *only* source of a DCF growth estimate as Dr. Olson has elected to do in this case. In other words, projected earnings growth rates are influential in, but not the only factor that is determinative of, investor expectations.

Q. PLEASE EXPLAIN WHY EXCLUSIVE RELIANCE ON ANALYSTS' PROJECTED EARNINGS GROWTH RATES IN A DCF EQUITY COST ESTIMATE CAN PRODUCE UNRELIABLE RESULTS.

A. First, it is important to realize that projected growth rates may over- or understate growth that can be sustained over time by the companies under review. This is important because sustainable growth is required in an accurate DCF assessment of the cost of equity capital. The efficacy of projected earnings growth rates in any specific DCF analysis can only be determined through a study of the underlying fundamentals of growth—something which Company witness Olson fails to do with his exclusive reliance on analysts' earnings growth rate projections.

Second, there is often associated with the exclusive use of analysts' projected earnings growth rates an erroneous notion of "consensus," i.e., that projected earnings growth rates are precisely what investors are using to estimate return requirements and that those estimates closely agree. As shown in the table below, which shows detailed statistics from Zack's' most recently available growth rates for the companies in my sample group (many of which are also in Dr. Olson's sample group), what is often called a "consensus" earnings growth expectation are, in reality, quite divergent.

Finally, as evidenced in financial news headlines, the sell-side institutional analysts that are polled by Zack's and similar services sometimes offer relatively "rosy" expectations for the stock they follow—even when the analyst's actual expectations for the stock are not so sanguine. Simply put, some analysts are simply overstating growth expectations to make the stocks look better. Although claims are often made that the opinions of sell-side analysts are not affected by the profits made by the other parts of the business that actually trade those securities, the recent event in the marketplace underscore that concern. Therefore, while what is known as the "Cinderella effect" (analysts' overstating stock expectations) is not a new phenomenon, the recent concern in the financial markets regarding this issue underscores the need for caution in the use of earnings growth expectations in estimating the cost of equity capital.

Q. DON'T WITNESSES WHO RELY EXCLUSIVELY ON EARNINGS GROWTH PROJECTIONS CITE ACADEMIC STUDIES WHICH SHOW ANALYSTS' EARNINGS GROWTH ESTIMATES TO BE "SUPERIOR" TO OTHER GROWTH RATE ESTIMATION METHODS?

A. Yes, however, while such studies do show that projected growth rates are superior to simple, mechanical averages of historical growth rates, they do not in any way suggest that projected earnings growth rates, alone, are determinative of investor expectations. What those studies actually do is make a good case for the consideration of analysts' growth rate forecasts in a reasoned examination of investor growth rate expectations. I agree with that premise, and that is how I use analysts' forecasts in my DCF analyses, i.e., as part of an analysis of growth rate expectations. Those studies do not, however, provide a rationale for an *exclusive* reliance in earnings growth rate projections. Certainly analysts' growth rate projections can influence investor expectations, but it is unreasonable to conclude, as Dr. Olson appears to do in this case, that they determine those expectations exclusively.

Q. DOES THAT CONCLUDE YOUR COMMENTS REGARDING DR. OLSON'S DCF ANALYSIS?

A. Yes, it does.

Q. WHAT ARE YOUR COMMENTS ON THE MECHANICS OF THE RISK PREMIUM METHODOLOGY?

A. A fundamental precept on which the risk premium methodology is based holds that the higher risk of stocks over bonds requires an incrementally higher return for those stocks in order for investors to be compensated for assuming the higher risk (e.g., see Olson Direct, pp. 16). Although that is generally true, it is most important to realize that, given a current bond yield of 6% for A-rated utilities, an equity return of 7%, 9% or even 25% would fulfill the requirement of providing "a premium" over debt costs. The real issue with a risk premium analysis is determining with any precision the return premium that investors require to invest in stocks rather than bonds. It is not a directly observable phenomenon and must be estimated.

There are two other fundamental tenets on which risk premium-type analyses are grounded which, when examined, indicate that this equity cost estimation methodology should not be given primary consideration in setting allowed rates of return. First, since risk premium analyses look backward in time[11], they assume "past is prologue." In other words, the investors' expectations for the future are assumed to mirror the average results they have experienced in the past. Second, implicit in the use of an average historical return premium of equities over debt is the assumption that the risk premium is constant over time because only one value is used to represent the risk premium expectation of investors. Neither of these assumptions on which the risk premium analysis rests is true.

The relative risk differentials between bonds and stocks are different now than they have been over the 72-year period from which Dr. Olson draws his risk premium data. The Ibbotson data indicate that, beginning in the 1970's, bond returns became substantially more volatile than they had been an anytime previously and, further, showed return

[11] Witness Olson notes at page 22 of his Direct that the data on which his Risk Premium analyses are from Ibbotson Associates Stocks, Bonds, Bills and Inflation: 2003 Yearbook, which studies return differentials from 1926 through 2002.

volatility similar to that of common stocks. It follows, then, that the investor-required return differential between stocks and bonds has been substantially different (smaller) over the past 30 years than it was prior to that time due to the increased volatility which is now inherent in the bond market. In other words, the very long-term return differentials between stocks and bonds used by Dr. Olson do not capture the current expected return differential.

Second, risk premiums are not static and vary significantly from period to period. The Ibbotson data on which Mr. Olson's risk premium is based indicate that common stock annual returns have ranged from +54% to -43%, while bond returns have ranged from +42% to -9%. Therefore, the assumption implicit in the Risk Premium analysis that risk premiums are static over time and that historical average results are equivalent to current expectations is simply not a reasonable basis on which to estimate current equity capital cost rates.

The practical impact of the volatility of historical risk premium data is that with the selection of any particular period over which to average the historical data, virtually any risk premium result can be produced. In addition, the use of historical earned return data (such as that published by Ibbotson Associates) to estimate current equity capital costs has been questioned in the financial literature:

> There are both conceptual and measurement problems with using I&S [Ibbotson and Sinquefield] data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome. ("The Risk Premium Approach to Measuring a Utility's Cost of Equity," Brigham, Shome and Vinson, <u>Financial Management</u>, Spring 1985, p. 34.)

Q. DO YOU HAVE OTHER SPECIFIC COMMENTS REGARDING MR. OLSON'S RISK PREMIUM ANALYSIS?

A. Yes, in addition to the general infirmities of such an analysis, outlined above, Mr. Olson's risk premium analysis is flawed by the fact that it produces a cost of equity that is not applicable to an electric utility operation. For example, Mr. Olson takes the Ibbotson Associates total return difference between common stocks and corporate bonds over the 1926-2002 period (6%) and adds that historical risk premium to the corporate bond rate prevailing at the time he performed his analysis (6.4%). That analysis produces a cost of capital for common stocks of 12.6% (Olson Direct, p. 23). However, that cost of capital estimate is based on Ibbotson's historical returns for the stock market as proxied by the S&P 500 index—an index of unregulated industrial firms. Dr. Olson makes an ad hoc adjustment to that result to account for the lower risk APS, and, based on a risk premium analysis estimates the equity capital cost of APS to range from 12% to 12.5%. However, as he, himself, notes that 40 basis point decrement is not based on quantifiable data.

If the Ibbotson historical risk premium of 6% used by Mr. Olson were adjusted for the difference in risk between the S&P 500 (the basis for Ibbotson's risk premium) and electric utility stocks, a more accurate estimate of the Company's cost of equity might ensue. For example, if the 6% risk premium were adjusted by a electric utility beta coefficient (0.67, see Exhibit_(SGH-1), Schedule 8) a more appropriate risk premium above bond yields for electric utilities would be 4.02% (6% x 0.67). That risk premium added Dr. Olson's bond yield of 6.4% would produce an equity cost estimate for APS of 10.04%—well below the 12.0%-12.5% he indicates is produced by his Risk Premium analysis[12]. Clearly, Dr. Olson's Risk Premium results is based primarily on the historical returns of unregulated industrial firms and is not adjusted in any quantifiable fashion or sufficiently to represent the risk differential between unregulated industrial firms and electric utility operations.

The purpose of this proceeding is to set rates for the utility operations of Arizona Public Service Company, not an average competitive industrial firm. Therefore, Mr.

[12] There is evidence published recently that risk premiums obtained from the Ibbotson studies are exaggerated. Moreover, those more recent studies show that a more normal risk premium between stocks and bonds ranges from 2% to 3% (Siegel, J., Stocks for the Long Run, 1994, Irwin, Chicago IL, p. 20). In that regard a risk premium at lower end of that range, 2%, which would be appropriate for less-risky utilities, added to Dr. Olson's 6.4% utility bond yield would produce a cost of equity estimate of 8.4%—below the lower end of my range of equity cost estimates for APS

Olson's risk premium analyses which rely on risk premiums based primarily on historical earned return data derived from unregulated, competitive industrial enterprises is not appropriate for ratesetting purposes. The results of Mr. Olson's risk premium analyses overstate the cost of capital of APS.

Q. DOES THIS COMMISSION RELY ON A RISK PREMIUM-TYPE ANALYSES IN SETTING ALLOWED EQUITY RETURNS?

A. No. It has been my experience that this Commission has, in the past, placed primary emphasis on the DCF methodology of estimation equity capital costs and does not place great weight on risk premium-type analyses.

Q. DOES THIS CONCLUDE YOUR COMMENTS ON DR. OLSON'S COST OF CAPITAL TESTIMONY?

A. Yes, it does.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, MR. HILL?

A. Yes, it does.

APPENDIX A

EDUCATION AND EMPLOYMENT HISTORY
OF
STEPHEN G. HILL

EDUCATION

Auburn University - Auburn, Alabama - Bachelor of Science in Chemical Engineering (1971); Honors - member Tau Beta Pi national engineering honorary society, Dean's list, candidate for outstanding engineering graduate; Organizations - Engineering Council, American Institute of Chemical Engineers

Tulane University - New Orleans, Louisiana - Masters in Business Administration (1973); concentration: Finance; awarded scholarship; Organizations - member MBA curriculum committee, Vice-President of student body, academic affairs

Continuing Education - NARUC Regulatory Studies Program at Michigan State University

EMPLOYMENT

West Virginia Air Pollution Control Commission (1975)
Position: Engineer ; Responsibility: Overseeing the compliance of all chemical companies in the State with the pollution guidelines set forth in the Clean Air Act.

West Virginia Public Service Commission-Consumer Advocate (1982)
Position: Rate of Return Analyst ; Responsibility: All rate of return research and testimony promulgated by the Consumer Advocate; also, testimony on engineering issues, when necessary.

Hill Associates (1989)
Position: Principal; Responsibility: Expert testimony regarding financial and economic issue in regulated industries.

PUBLICATIONS

"The Market Risk Premium and the Proper Interpretation of Historical Data," Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, Volume I, pp. 245-255.
"Use of the Discounted Cash Flow Has Not Been Invalidated," Public Utilities Fortnightly, March 31, 1988, pp. 35-38.

MEMBERSHIPS

American Institute of Chemical Engineers; Society of Utility and Regulatory Financial Analysts (Certified Rate of Return Analyst, Member of the Board of Directors)

APPENDIX B

Q. PLEASE PROVIDE AN EXAMPLE WHICH DESCRIBES THE DETERMINANTS OF LONG-TERM SUSTAINABLE GROWTH.

A. Assume that a hypothetical regulated firm had a first period common equity or book value per share of $10, the investor-expected return on that equity was 10% and the stated company policy was to pay out 60% of earnings in dividends. The first period earnings per share are expected to be $1.00 ($10/share book equity x 10% equity return) and the expected dividend is $0.60. The amount of earnings not paid out to shareholders ($0.40), the retained earnings, raises the book value of the equity to $10.40 in the second period. The table below continues the hypothetical for a five year period and illustrates the underlying determinants of growth.

TABLE A.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
EQUITY RETURN	10%	10%	10%	10%	10%	-
EARNINGS/SH.	$1.00	$1.040	$1.082	$1.125	$1.170	4.00%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	-
DIVIDENDS/SH.	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

We see that under steady-state conditions, the earnings, dividends and book value all grow at the same rate. Moreover, the key to this growth is the amount of earnings retained or reinvested in the firm and the return on that new portion of equity. If we let "b" equal the retention ratio of the firm (1 – the payout ratio) and let "r" equal the firm's expected return on equity, the DCF growth rate "g" (also referred to as the internal or sustainable growth rate) is equal to their product, or

$$g = br. \qquad \text{(i)}$$

Professor Myron Gordon, who developed the Discounted Cash Flow technique and first introduced it into the regulatory arena, has determined that Equation (i) embodies the underlying fundamentals of growth and, therefore, is a primary measure of growth to be used in the DCF model. Professor Gordon's research also indicates that analysts' growth rate projections are useful in estimating investors' expected sustainable growth.

I should note here that the above hypothetical does not allow for the existence of external sources of equity financing, i.e., sales of common stock. Stock financing will cause investors to expect additional growth if the company is expected to issue new shares at a market price that exceeds book value. The excess of market over book would inure to current shareholders, increasing their per share equity value. Therefore, if the company is expected to continue to issue stock at a price that exceeds book value, the shareholders would continue to expect their book value to increase and would add that growth expectation to that stemming from earnings retention or internal growth. Conversely, if a company were expected to issue new equity at a price below book value, that would have a negative effect on shareholder's current growth rate expectations. In such a situation, shareholders would perceive an overall growth rate less than that produced by internal sources (retained earnings). Finally, with little or no expected equity financing or a market-to-book ratio near unity, investors would expect the sustainable growth rate for the company to equal that derived from Equation (i), "g = br." Dr. Gordon[1] identifies the growth rate which includes both expected internal and external financing as:

$$g = br + vs, \qquad \text{(ii)}$$

where,

g = DCF expected growth rate,
r = return on equity,
b = retention ratio,
v = fraction of new common stock sold that accrues to the current shareholder,
s = funds raised from the sale of stock

[1]Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp., 30–33.

as a fraction of existing equity.

Additionally,

$$v = 1 - BV/MP, \tag{iii}$$

where,

MP = market price,
BV = book value.

I have used Equation (iii) as the basis for my examination of the investor expected long-term growth rate (g) in this proceeding.

Q. IN YOUR PREVIOUS EXAMPLE, EARNINGS AND DIVIDENDS GREW AT THE SAME RATE (br) AS DID BOOK VALUE. WOULD THE GROWTH RATE IN EARNINGS OR DIVIDENDS, THEREFORE, BE SUITABLE FOR DETERMINING THE DCF GROWTH RATE ?

A. No, not necessarily. Rates of growth derived from earnings or dividends alone can be unreliable due to extraneous influences on those parameters such as changes in the expected rate of return on common equity or changes in the payout ratio. That is why it is necessary to examine the underlying determinants of growth through the use of a sustainable growth rate analysis.

If we take the hypothetical example previously stated and assume that, in year three, the expected return on equity rises to 15%, the resultant growth rate for earnings and dividends far exceeds that which the company could sustain indefinitely. The potential error in using those growth rates to estimate "g" is illustrated in the following table.

TABLE B.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.47	$12.157	5.00%
EQUITY RETURN	10%	10%	15%	15%	15%	10.67%
EARNINGS/SH.	$1.00	$1.040	$1.623	$1.720	$1.824	16.20%
PAYOUT RATIO	0.60	0.60	0.60	0.60	0.60	-
DIVIDENDS/SH.	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

What has happened is a shift in steady-state growth paths. For years one and two, the sustainable rate of growth (g=br) is 4.00%, just as in the previous hypothetical. Then, in the last three years, the sustainable growth rate increases to 6.00% (g=br = 0.4x15%). If the regulated firm were expected to continue to earn a 15% return on equity and retain 40% of its earnings, then a growth rate of 6.0% would be a reasonable estimate of the long-term sustainable growth rate. However, the compound annual growth rate for dividends and earnings exceeds 16% which is the result only of an increased equity return rather than the intrinsic ability of the firm to grow continuously at a 16% annual rate. Clearly, this type of estimate of future growth cannot be used with any reliability at all. In the case of the hypothetical, to utilize a 16% growth rate in a DCF model would be to expect the company's return on common equity to increase by 50% every five years into the indefinite future. This would be a ridiculous forecast for any regulated firm and underscores the importance of utilizing the underlying fundamentals of growth in the DCF model.

It can also be demonstrated that a change in our hypothetical regulated firm's payout ratio makes the past rate of growth in dividends an unreliable basis for predicting "g". If we assume our regulated firm consistently earns its expected equity return (10%) but in the third year, changes its payout ratio from 60% to 80% of earnings, the results are shown in the table below.

TABLE C.

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	GROWTH
BOOK VALUE	$10.00	$10.40	$10.82	$11.036	$11.26	3.01%
EQUITY RETURN	10%	10%	10%	10%	10%	-
EARNINGS/SH.	$1.00	$1.040	$1.082	$1.104	$1.126	3.01%
PAYOUT RATIO	0.60	0.60	0.80	0.80	0.80	7.46%
DIVIDENDS/SH.	$0.60	$0.624	$0.866	$0.833	$0.900	10.67%

What we see here is that, although the company has registered a high dividend growth rate (10.67%), it is, again, not at all representative of the growth that could be sustained indefinitely, as called for in the DCF model. In actuality, the sustainable growth rate has declined from 4.0% the first two years to only 2.0% (g=br = 0.2x10%) during the last three years due to the increased payout ratio. To utilize a 10% growth rate in a DCF analysis of this hypothetical regulated firm would 1) assume the payout ratio of the firm would continue to increase 33% every five years into the indefinite future, 2) lead to the highly implausible result that the firm intends to consistently pay out more in dividends than it earns and 3) grossly overstate the cost of equity capital.

APPENDIX C
SAMPLE COMPANY GROWTH RATE ANALYSES

ELECTRIC UTILITIES

CV – Central Vermont Public Service - CV's sustainable growth rate has averaged only 0.8% over the most recent five year period (1998-2002), including a set-back with substantially negative growth in 1998, due to purchased power contract difficulties. Absent that negative growth, the company's average historical sustainable growth is 2%. Also, the company's sustainable growth in the most recent year, about 4%, indicates an increasing growth trend. VL expects CV's sustainable growth to rise above that historical growth rate level and reach 4.6% by the 2006-2008 period. CV's book value growth rate is expected to be 2% over the next five years, a significant increase from the 0.5% rate of growth experienced over the past five years, but far below internal growth projections. Also, CV's earnings per share are projected to increase at a 7.5% (VL) rate—above the indicated sustainable growth rate—but its dividends are expected to show 3% growth over the next five years, moderating long-term sustainable growth expectations. Over the past five years, CV's earnings growth was negative (giving rise to the expectation for much higher growth in the future) while its dividends increased at only a 1% rate. Investors can reasonably expect a sustainable growth rate in the future to be higher than the past; a growth rate of **4.75%** is reasonable for CV.

Regarding share growth, CV's shares outstanding increased at a 0.6% rate over the past five years. The growth the number of shares is projected by VL to increase at about a the same rate – 0.6% -- between 2002 and the 2006-08 period. An expectation of share growth of **0.6%** for this company is reasonable.

EAS –Energy East Corp - EAS's sustainable growth rate averaged about 6.5% for the five-year historical period, with a substantial growth rate decrease in the most recent year. Value Line projects more moderate growth from 2003 through 2006-08 period at a level near 4%. However, EAS's book value growth during the most recent five years (4%) is expected to increase to a 5% rate in the future. EAS's earnings per share are projected to increase at a 1% (VL) to 5.0% (Zack's) or 6.0% (Thomson Financial) rate, but its dividends are expected to grow at a 4.0% rate, moderating earnings growth expectations. Historically EAS's earnings have shown 8% growth, while its dividends increased at a 5.5% rate. Investors can reasonably expect a sustainable growth rate lower than that established historically; **4.5%** is a reasonable expectation for this company.

Regarding share growth, EAS's shares outstanding grew at approximately an 3.5% rate over the past five years due to an equity issuance in 2002. Prior to that equity issuance the number of shares outstanding had declined at a 2.5% rate. The number of shares is expected to grow at approximately a 0.7% rate through 2006-08. An expectation of share growth of **1%** for this company is reasonable.

FE – FirstEnergy Corp. - FE's sustainable growth rate averaged 4.3% over the five-year historical period. VL projects that the internal growth will be stable through 2006-08, bringing sustainable growth to 4.33%. FE's book value, which increased at a 6.5% rate during the most recent five years, is expected to decline to a 4.5% rate in the future, very similar to the sustainable growth projection. FE's earnings per share are projected to increase at a 2% (VL) to 4.0% (Zack's and

Thomson Financial) rate, and its dividends are expected to grow at a 2% rate, moderating long-term growth expectations. Historically FE's earnings grew at an 6% rate, according to Value Line and its dividends showed essentially no growth. On a compound growth rate basis using 2003 projections as the final year, FE's earnings grew at a –0.52% rate historically. The projected sustainable growth, earnings and book value growth rate data indicate that investors can expect the growth from FE in the future to be similar to or lower than that which has existed in the past. Investors can reasonably expect a sustainable growth rate of **4.5%** for FE.

Regarding share growth, FE's shares outstanding showed a 5.8% increase over the past five years. Further, after showing similar growth from 2002 to 2003, FE's growth rate in shares outstanding is expected to fall to about a 1.5% rate of increase through 2006-08. Those projections indicate that future share growth will be below past averages. An expectation of share growth of **2%** for this company is reasonable.

SO – Southern Company - SO's sustainable growth rate has averaged 3.37% over the most recent five year period. VL expects SO's sustainable growth to rise above that historical growth rate level and reach approximately 5% by the 2006-2008 period. SO's book value growth rate is expected to be 5% over the next five years, up dramatically from the -1% rate of growth experienced over the past five years. Also, SO's earnings per share are projected to increase at a 4.6% (Zack's), 5.0% (Thomson Financial) to 5.5% (VL) rate—bracketing the indicated sustainable growth rate. However, its dividends are expected to grow at 3%. Over the past five years, SO's earnings growth was 2% according to Value Line (only 1.35% on a compound basis) while its dividends increased at a 1.5% rate. Investors can reasonably expect a higher sustainable growth rate in the future — **5%** for SO is reasonable.

Regarding share growth, SO's shares outstanding increased at approximately a 0.6% rate over the past five years. The number of shares is expected to grow at a 1.46% rate through 2006-08. An expectation of share growth of **1.25%** for this company is reasonable.

AEE – Ameren Corp. - AEE's sustainable growth rate averaged only about 2% over the most recent five-year period, with a poor year in the most recent year. Absent the most recent year AEE's sustainable growht averaged 2.35% with an increasing trend. VL projects, by the 2006-08 period, sustainable growth will approximate 2.3%-a-some improvement over the actual five-year average. AEE's projected book value also indicates improvement -- book value grew at a 1.5% rate during the most recent five years but is expected to rise at an 3.5% rate in the future, according to Value Line. Value Line projects a rate of earnings increase for AEE of 1%, while Thomson Financial projects 3% and Zack's projects 2.9%. Dividends are expected to grow at a 0.5% rate, moderating long-term growth expectations somewhat. Historically AEE's earnings grew at a 2.5% rate while its dividends increased at a 0.5% rate. Therefore, Investors can reasonably expect a long-term sustainable growth rate from this company of **3.0%.**

Regarding share growth, AEE's shares outstanding grew at a 2.94% rate over the past five years. The five-year average level of share growth is expected to decrease at approximately 2% annually through 2006-08. An expectation of share growth of **2.5%** for this company is reasonable.

CNL – Cleco Corp. - CNL's sustainable growth rate averaged 5.03% for the five-year period, with the results in the most recent year, approximating that average. VL expects sustainable growth to continue at about a 5% level through the

2006-08 period. CNL's book value growth is expected to continue to increase at a 3%, below the historical level of 5.5%. CNL's earnings per share is projected to show no growth over the next five years, and its dividends are expected to grow at only a 0.5% rate. Historically CNL's earnings increased at a 6.5% rate and its dividends increased at a 2.5% rate of growth, according to Value Line. Investors can reasonably expect sustainable growth from CNL to be below past averages, a sustainable internal growth rate of **4.75%** is reasonable for this company.

Regarding share growth, CNL's shares outstanding grew at approximately a 1.1% rate over the past five years. The growth in the number of shares is expected by VL to be 0.6% through 2006-08. An expectation of share growth of **0.75%** for this company is reasonable.

DPL – DPL Inc. - DPL's sustainable growth rate has averaged 5.1% over the most recent five year period with negative results in the most recent year. Absent the 2002 results, DPL's average growth was 7.2%. VL expects DPL's sustainable growth to rise above that historical growth rate level to 9% by the 2006-2008 period. DPL's book value growth rate is expected to be 6% over the next five years, up dramatically from the -3% rate of growth experienced over the past five years. Also, DPL's earnings per share is projected to increase at a 6% (VL) to 4.5% (Zack's) to 4% (Thomson Financial) rate—all well below the indicated internal growth rate. Also, its dividends are expected to grow at only 0.5%, moderating long-term growth rate expectations. Over the past five years, DPL's earnings growth was 3% while its dividends increased at a 1.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **5.75%** for DPL.

Regarding share growth, DPL's shares outstanding decreased at approximately a 6% rate over the past five years. The number of shares outstanding in 2006-2008 is expected to be the same as that existing in 2002—therefore no growth is expected in the future. An expectation of share growth of **0%** for this company is reasonable.

EDE – Empire District Electric - EDE's sustainable internal growth rate averaged –0.79% over the five-year historical period, with several negative growth years. VL projects EDE's sustainable growth to rise to a level of almost 3% through 2006-08. Also, EDE's book value growth rate is expected to continue in the future at 3%, double the historical level of 1.5%, pointing to increasing growth for this company. EDE's earnings per share are projected to increase at 9% to 10% according to VL & Zack's, respectively while the analysts' surveyed by Thomson Financial (IBES) project earnings growth at 3.0%, a substantial difference. EDE's dividends are expected to remain at a constant level over the next five years (i.e., showing 0% growth). Sustainable growth has been relatively inconsistent for this company, historically and is expected to trend upward in the future to near the 3% level. Dividend growth has been non-existent. Also Value Line's earnings growth projection is skewed upward by their inclusion of the company's 2001 earnings in is "base" three-year period. From 2003 through the mid-point of the 2006-2008 period, Value Line's projected earnings per share indicate a 4% growth rate. investors can reasonably expect a sustainable growth rate of **3.5%** from EDE.

Regarding share growth, EDE's shares outstanding grew at about a 7% rate over the past five years, due primarilyi to a large equity issuance in 2002. The level of share growth is expected by VL to drop to 1% through 2006-08. An expectation of share growth of **2.5%** for this company is reasonable.

ETR – Entergy Corp. - ETR's internal sustainable growth rate has averaged 4.81% over the most recent five year period (1998-2002), with results in 2000 through 2002 above the historical growth rate level, indicating an increasing trend.

That higher level of growth is expected to be sustained in 2003 and to rise to approximately 5.2% by the 2006-2008 period. ETR's book value growth rate is expected to be 6.5% over the next five years—an substantial increase from the 3.5% rate of growth experienced over the past five years also pointing to higher growth expectations for the future. ETR's earnings per share are projected to increase at a rate of from 5.5% (VL) to 6.1% (Zack's) to 6.0% (Thomson Financial). After showing negative growth historically ETR's dividends are expected to grow at a high 8.5%, supporting higher sustainable growth expectations. Over the past five years, ETR's earnings grew at a 7% rate while its dividends showed –6.5% growth. Investors can reasonably expect a sustainable growth rate in the future to be higher than past averages, **6.00%** is reasonable for for ETR.

Regarding share growth, ETR's shares outstanding grew at a –2.5% rate over the past five years. The number of shares outstanding is projected by VL to rise at approximately a 0.75% rate through 2006-08. An expectation of share growth of **0.25%** for this company is reasonable.

GXP – Great Plain Energy - GXP's sustainable growth rate has averaged only 0.7% over the most recent five year period, with two negative years. VL expects GXP's sustainable growth to rise above that historical growth rate level to about 4.8% by the 2006-2008 period. GXP's book value growth rate is expected to be 3.5% over the next five years, above the –1.0% rate of growth experienced over the past five years. GXP's earnings per share are projected to increase at a rate of 4.5% (VL) to 4.0% (Zack's) to 4.0% (Thomson Financial). However, like many other electric companies, its dividends are expected to grow at only 0.5%. Over the past five years, GXP's earnings growth was 1.5% while its dividends increased at a 1% rate. Investors can reasonably expect a sustainable growth rate in the future of **4.25%** for GXP.

Regarding share growth, GXP's shares outstanding increased at approximately a 2.8% rate over the past five years due to an equity issuance in 2002—for the four years prior, there was no growth. That rate of increase is expected to slow in the future with number of shares outstanding in 2006-2008 is expected to remain essentially constant. An expectation of share growth of **0.5%** for this company is reasonable.

HE – Hawaiian Electric - HE's sustainable growth rate has averaged 1.77% over the most recent five year period (1998-2002), with higher growth in the two most recent years, indicating an increasing trend. However, VL expects HE's sustainable growth to moderate from that historical growth rate level to reach 1.5% by the 2006-2008 period. However, HE's book value growth rate is expected to be 3.5% over the next five years, a significant increase from the 1.5% rate of growth experienced over the past five years. Also, HE's earnings per share are projected to increase at a 2.8% (Thomson Financial) to 2.9% (Zack's) rate—while Value Line expects no growth in per share earnings for HE. The company's dividends are expected to show no growth over the next five years. Over the past five years, HE's earnings grew at a relatively slow rate (2.5%--giving rise to the expectation for much higher growth in the future) while its dividends increased at only a 0.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **3.0%** for HE.

Regarding share growth, HE's shares outstanding grew at a 3.5% rate over the past five years. The number of shares is projected by VL to increase at about a 1.2% between 2002 and the 2006-08 period. An expectation of share growth of **2.25%** for this company is reasonable.

PNW – Pinnacle West Capital Corp - PNW's sustainable growth rate averaged about 6% for the five-year historical period, with a growth rate in the most recent year below historical averages, indicating a declining trend. Value Line projects that growth moderation to continue and a sustainable growth rate by the 2006-08 period at a level near 3.5%. Also, PNW's book value growth during the most recent five years (5%) is expected to moderate to a 3% rate in the future, confirming slower growth expectations. PNW's earnings per share are projected to increase at a 0.5% (VL) to 5.3% (Zack's) to 5.0% (Thomson Financial). However, its dividends are expected to grow at a 5.5% rate, similar to some earnings growth expectations. Historically PNW's earnings have shown 5% growth, while its dividends increased at an 8.5% rate. Investors can reasonably expect a sustainable growth rate lower than that established historically, but not as high as the earnings growth projected by analysts; **4.5 %** is a reasonable expectation for this company.

Regarding share growth, PNW's shares outstanding grew at approximately a 1.8% rate over the past five years. The number of shares is expected to grow at approximately a 0% rate through 2006-08. An expectation of share growth of **0.5%** for this company is reasonable.

APPENDIX D

CORROBORATIVE EQUITY CAPITAL COST ESTIMATION METHODS

CAPITAL ASSET PRICING MODEL

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL (CAPM) YOU USED TO ARRIVE AT AN ESTIMATE FOR THE COST RATE OF THE COMPANY'S EQUITY CAPITAL.

A. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (systematic) risk of a security. Systematic risk refers to the risk associated with movements in the macro-economy (the economic "system") and, thus, cannot be eliminated through diversification by holding a portfolio of securities. The beta coefficient (β) is a statistical measure which is an attempt to quantify the non-diversifiable risk of the return on a particular security against the returns inherent in general stock market fluctuations. The formula is expressed as follows:

$$k = r_f + \beta(r_m - r_f), \qquad \text{(i)}$$

where "k" is the cost of equity capital of an individual security, "r_f" is the risk-free rate of return, "β" is the beta coefficient, "r_m" is the average market return and "r_m - r_f" is the market risk premium. The CAPM is used in my analysis, not as a primary cost of equity analysis, but as a check of the DCF cost of equity estimate. Although I believe the CAPM can be useful in testing the reasonableness of a cost of capital estimate, certain theoretical shortcomings of this model (when applied in cost of capital analysis) reduce its usefulness.

Q. CAN YOU EXPLAIN WHY YOU APPLY THE CAPM ANALYSIS WITH CAUTION?

A. Yes. The reasons why the CAPM should be used in cost of capital analysis with caution are set out below. It is important to understand that my caution with regard to the use of the CAPM in a cost of equity capital analysis does not indicate that the model is not a useful description of the capital markets. Rather, it recognizes that in the practical application of the CAPM to cost of capital analysis there are problems that can cause the results of that type of analysis to be less reliable than other, more widely accepted models such as the DCF.

The CAPM was originally designed as a point-in-time tool for selecting stock portfolios that matched a particular investor's risk/return preference. Its use in rate of return analysis to estimate multi-period return expectations for one stock or one type of stock, rather than a diversified portfolio of stocks, takes the model out of the context for which it was intended. Also, questions regarding the fundamental applicability of the CAPM theory and the accuracy of beta have arisen recently in the financial literature.

Over the past few years there has been much comment in the financial literature over the strength of the assumptions that underlie the CAPM and the inability to substantiate those assumptions through empirical analysis. Also, there are problems with the key CAPM risk measure that indicate that the CAPM analysis is not a reliable primary indicator of equity capital costs.

Cost of capital analysis is a decidedly forward-looking, or *ex-ante*, concept. Beta is not. The measurement of beta is derived completely with historical, or *ex-post*, information. Therefore, the beta of a particular company, because it is usually derived with five years of historical data, is slow to change to current (i.e., forward-looking) conditions, and some price abnormality that may have happened four years ago could substantially affect beta while, currently, being of little actual concern to investors. Moreover, this same shortcoming which assumes that past results mirror investor expectations for the future plagues the market risk premium in an ex-post, or historically-oriented CAPM.

Also, a recent study performed for the Center for Research in Security Prices at the University of Chicago Graduate School of Business shows that the assumed linear relationship between beta, risk and return (i.e., beta varies directly with risk and return) simply does not appear to exist in the marketplace. As Value Line reported in its Industry

Review published in March of 1992:

> Two of the most prestigious researchers in the financial community, Professors Eugene F. Fama and Kenneth R. French from the University of Chicago have challenged the traditional relationship between Beta and return in a recent paper published by the Center for Research in Security Prices. In this study, the duo traced the performance of thousands of stocks over 50 years, but found no statistical support for the hypothesis that the relationship between volatility and return is significantly different from random. Indeed, professor Fama concluded, 'The fact is that Beta, as the sole variable explaining returns on stocks, is dead.' These findings support previous studies that have called into question the real-world applicability of the CAPM Beta, including papers by Keim (Financial Analysts Journal, 1986), and Roll (Journal of Financial Economics, 1977). Never before, however, has the lack of a statistically significant relationship between beta and return been so rigorously and dramatically established. (Value Line Industry Review, March 13, 1992, p. 1-8.)

Fama and French have continued their investigation of the CAPM since their 1992 article and have postulated that a more accurate CAPM would use two additional risk measures in addition to beta. Their three-factor CAPM uses relative size as measured by market value of the firm's stock compared to that of the market index and relative book value-to-market value ratio compared to that of the market index as additional measures of risk[1]. The continuing research of Fama and French indicate that their three-factor CAPM is theoretically superior to the "standard" CAPM which relies on betas as the sole indicator of relative risk, producing results which more closely mimic historical experience.

However, it is important to note that while those authors tout the superiority of their three-factor CAPM to the single-beta CAPM on theoretical grounds, they recognize that there are significant problems with any type of asset pricing model when it comes to

[1] Fama and French postulate that firm size and book-to-market ratio effectively proxy the risk-return characteristics of earnings-price ratios and sales growth, the latter having been determined to have more explanatory power with regard to relative risk and return than beta alone.

using the model to estimate the cost of equity capital. In "Industry Costs of Equity" a working paper published by the Center for Research in Security Prices (Revised October 1996), Fama and French point out quite clearly that the volatility inherent in the historical data is such that a cost of equity estimate produced by <u>any</u> asset pricing model -- whether the traditional CAPM or their three-factor CAPM -- is subject to wide error:

> We do not take a stance on which is the right asset pricing model. Instead we use both the CAPM and our three-factor model to estimate industry costs of equity (CE's). Our goal is to illustrate in detail two problems that plague CE estimates from any asset pricing model.
>
> The first problem is imprecise estimates of risk loadings [betas or beta-equivalents for other risk measures]. Estimates of CAPM and three-factor risk loadings for industries would be precise if the loadings were constant. We find however, that there is strong variation through time in the CAPM and three-factor risk loadings of industries. As a result, if we are trying to measure an industry's current risk loadings and cost of equity, estimates from full sample (1963-1994) regressions are not more accurate than the imprecise estimates from regressions that use only the latest three years of data. And industries give an understated picture of the problems that will arise in estimating risk loadings for individual firms and investment projects.
>
> The second problem is imprecise estimates of factor risk premiums. For example, the price of risk in the CAPM is the expected return on the market portfolio minus the risk-free interest rate, $E(R_M)$-R_f. The annualized average excess return on the Center for Research in Security Prices (CSRP) value-weighted market portfolio of NYSE, AMEX and NASDAQ stocks for our 1963-1994 sample period is 5.16%; its standard error is 2.71%. Thus, if we use the historical market premium to estimate the expected premium, the traditional plus-and-minus-two-standard-error interval ranges from less than zero to more than 10.0%.
>
> Our message is that uncertainty of this magnitude about risk premiums, coupled with the uncertainty about risk loadings, implies woefully imprecise estimates of the cost of equity. (Fama, French, "Industry Costs of Equity," Center for Research in Security Prices at the University of Chicago Graduate School of Business (First Draft March 1994, Revised October 1996), pp. 1-2)

While this relatively recently published conclusion as to the imprecision of equity cost estimates produced by CAPM-type models does not negate the risk/return basis of asset pricing, it does definitely call for a more accurate measure with which asset returns can be more reliably indexed. However, unless and until such an index is published and widely accepted in the marketplace, CAPM cost of equity capital estimates should be relegated to a supporting role or informational status. Therefore, for the reasons set out above, I use the CAPM for informational purposes and do not rely on that methodology as a primary equity capital cost estimation technique.

Q. WHAT VALUE HAVE YOU CHOSEN FOR A RISK-FREE RATE OF RETURN IN YOUR CAPM ANALYSIS?

A. As the CAPM is designed, the risk-free rate is that short-term rate of return investors can realize with certainty. The nearest analog in the investment spectrum is the 13-week U. S. Treasury Bill. Although longer-term Treasury bonds have equivalent default risk to T-Bills, those longer-term government securities carry maturity risk that the T-Bills do not have. When investors tie up their money for longer periods of time, as they do when purchasing a long-term Treasury, they must be compensated for future investment opportunities forgone as well as the potential for future changes in inflation. Investors are compensated for this increased investment risk by receiving a higher yield on T-Bonds.

As I noted in my previous discussion of the macro-economy, due to a sluggish economy, the Fed has acted vigorously over the past year to lower short-term interest rates. Over the most recent six-week period, T-Bills have produced an average yield of only 0.94% (data from Value Line *Selection & Opinion*, six most recent weekly editions[2]).

Q. DO YOU BELIEVE THE USE OF A LONG-TERM TREASURY BOND RATE IS APPROPRIATE IN THE CAPM?

---

[2] Current T-Bill yield, six-week average yield from Value Line Selection & Opinion (10/24/03-11/28/03).

A. No. Although the selection of a long- or short-term Treasury security as the risk free rate of return to be used in the CAPM is often one of the areas of contention in applying the model in cost of capital analysis, the use of a normalized short-term T-Bill rate is the more theoretically correct parameter. However, the T-Bill yield can be influenced by Federal Reserve policy, and, as noted above, the Fed's current stance regarding economic stimulation has caused the current level of T-Bills to fall to historic lows. Therefore, for purposes of analysis in this proceeding I will use both the T-Bill and long-term Treasury bond yields for the risk-free rate in the CAPM. Also, along with those measures of the risk-free rate I use the corresponding measures of market risk premiums.

Q. WHAT HAVE YOU CHOSEN AS THE MARKET RISK PREMIUM FOR THE CAPM ANALYSIS?

A. In their 2003 edition of Stocks, Bonds, Bills and Inflation, R.G. Ibbotson Associates indicates that the average market risk premium between stocks and T-Bills over the 1926–2002 time period is 8.4% (based on an arithmetic average), and 6.4% (based on a geometric average). For long-term Treasuries, the market risk premiums are 6.4% (based on an arithmetic average) and 4.7% (based on a geometric average). I have used these values to estimate the market risk premium in the CAPM analysis. The geometric mean is based on compound returns over time and the arithmetic mean is based on the average of single-period returns.

Q. WHAT VALUES HAVE YOU CHOSEN FOR THE BETA COEFFICIENTS IN THE CAPM ANALYSIS?

A. Value Line reports beta coefficients for all the stocks it follows. Value Line's beta is derived from a regression analysis between weekly percentage changes in the market price of a stock and weekly percentage changes in the New York Stock Exchange Composite Index over a period of five years. The average beta coefficient of the sample group of gas distribution companies is 0.66.

Q. WHAT IS YOUR RECOMMENDED COST OF EQUITY CAPITAL FOR THE SAMPLE OF ELECTRIC COMPANIES USING THE CAPITAL ASSET PRICING MODEL ANALYSIS?

A. Schedule 8 shows that the average Value Line beta coefficient for the group of electric companies under study is 0.67. The overall arithmetic average market risk premium of 8.4% would, upon the adoption of a 0.67 beta, become a sample group premium of 5.64% (0.67 x 8.4%). That non-specific risk premium added to the risk-free T-Bill rate of 0.94%, previously derived, yields a common equity cost rate estimate of 6.58%. Schedule 8 also shows that using an average long-term T-bond yield (5.18%) the CAPM produces equity cost estimates of 8.33% (geometric) and 9.47% (arithmetic).

In the current market environment, the CAPM result based on the current T-Bill produces a very low cost of equity estimate that is, in my view, below the Company's long-term cost of equity capital. The T-Bill CAPM results, currently, do not produce a return which is above the Company's debt costs and, thus, are not reliable as an indicator of the cost of equity.

The CAPM results which employ the long-term Treasury yields (8.33%/9.47%) are more reasonable in the current economic environment as an estimate of the Company's cost of equity capital. Those results are below the DCF results derived previously, indicating that 1) even long-term capital costs are currently quite low and 2) my DCF equity cost estimate may be higher than the companies' actual cost of equity capital.

MODIFIED EARNINGS-PRICE RATIO ANALYSIS

Q. PLEASE DESCRIBE THE MODIFIED EARNINGS-PRICE RATIO (MEPR) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL.

A. The earnings-price ratio is calculated simply as the expected earnings per share divided by the current market price. In cost of capital analysis, the earnings-price ratio (which is one portion of this analysis) can be useful in a corroborative sense, since it can be a good indicator of the proper range of equity costs when the market price of a stock is near its book value. When the market price of a stock is *below* its book value, the earnings-price ratio *overstates* the cost of equity capital. Schedule 9 contains mathematical support for this concept. The opposite is also true, i.e.; the earnings-price ratio *understates* the cost of equity capital when the market price of a stock is *above* book value.

Under current market conditions, the electric firms under study have an average market-to-book ratio of 1.67 and, therefore, the average earnings-price ratio alone would understate the cost of equity for the sample group. However, it is important to emphasize that I do not use the earnings-price ratio alone as an indicator of equity capital cost rates. Because of the relationship among the earnings-price ratio, the market-to-book ratio and the investor-expected return on equity, I have modified the standard earnings-price ratio analysis by including expected returns on equity for the companies under study. It is that modified analysis, the MEPR analysis, that I will use to assist in estimating an appropriate range of equity capital costs in this proceeding.

Q. PLEASE EXPLAIN THE RELATIONSHIP AMONG THE EARNINGS-PRICE RATIO, THE EXPECTED RETURN ON EQUITY AND THE MARKET-TO-BOOK RATIO.

A. When the investor-expected return on equity for a company exceeds the investor-required return (the cost of equity capital), the market price of the firm will tend to exceed its book value. As explained above, when the market price exceeds book value, the earnings-price ratio understates the cost of equity capital. Therefore, when the expected equity return (ROE) exceeds the cost of equity capital, the earnings-price ratio will understate that cost rate.

Also, in situations where the expected equity return is below what investors require for that type of investment, market prices fall below book value. Further, when market-to-book ratios are below 1.0, the earnings-price ratio overstates the cost of equity capital. Thus, the expected rate of return on equity and the earnings-price ratio tend to move in a countervailing fashion about the cost of equity capital. When market-to-book ratios are above one, the expected equity return exceeds and the earnings-price ratio understates the cost of equity capital. When market-to-book ratios are below one, the expected equity return understates and the earnings-price ratio exceeds the cost of equity capital. Further, as market-to-book ratios approach unity, the expected return and the earnings price ratio approach the cost of equity capital. Therefore, the average of the expected book return and the earnings price ratio provides a reasonable estimate of the cost of equity capital.

These relationships represent general rather than precisely quantifiable tendencies but are useful in corroborating other cost of capital methodologies. The Federal Energy Regulatory Commission, in its generic rate of return hearings, found this technique useful and indicated that under the circumstances of market-to-book ratios exceeding unity, the cost of equity is bounded above by the expected equity return and below by the earnings-price ratio (e.g., 50 Fed Reg, 1985, p. 21822; 51 Fed Reg, 1986, pp. 361, 362; 37 FERC ¶ 61,287). The mid-point of these two parameters, therefore, produces an estimate of the cost of equity capital which, when market-to-book ratios are different from unity, is far more accurate than the earnings-price ratio alone.

Q. WHAT ARE THE RESULTS OF YOUR EARNINGS-PRICE RATIO ANALYSIS OF THE COST OF EQUITY FOR THE SAMPLE GROUP?

A. Schedule 10 shows the Thomson Financial projected 2004 per share earnings for each of the firms in the sample groups. Recent average market prices (the same market prices used in my DCF analysis), Value Line's projected 2003 return on equity and 2006-2008 equity returns for each of the companies are also shown.

The average earnings-price ratio for the electric sample group, 7.14%, is below the cost of equity for those companies due to the fact that their average market-to-book ratio is currently above unity. The sample electric companies' 2003 expected book equity return averages 11.17%. That return rate is above the companies' cost of equity capital, again due to the fact that the market prices for those firms are above their book values. For the entire sample group, then, the mid-point of the earnings-price ratio and the current equity return is 9.16%.

Schedule 10 also shows that the average expected book equity return over the next three- to five-year period is 11.83%. The midpoint of these two boundaries of equity capital cost for the whole group, i.e., the long-term projected return on book equity (11.83%) and the current earnings-price ratio (7.14%) is 9.49%, and provides another forward-looking estimate of the equity capital cost rate of an electric utility firm. The results of this MEPR analysis also indicate that the DCF equity cost estimate previously derived may be overstated (i.e., too high).

MARKET-TO-BOOK RATIO ANALYSIS

Q. PLEASE DESCRIBE YOUR MARKET-TO-BOOK (MTB) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL FOR THE SAMPLE GROUP.

A. This technique of analysis is a derivative of the DCF model that attempts to adjust the capital cost derived with regard to inequalities that might exist in the market-to-book ratio. This method is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method. However, the MTB analysis is useful in a corroborative sense. The MTB seeks to determine the cost of equity using market-determined parameters in a format different from that employed in the DCF analysis. In the DCF analysis, the available data is "smoothed" to identify investors' long-term sustainable expectations. The MTB analysis, while based on the DCF theory, relies instead on point-in-time data projected one year and five years into the future and, thus, offers a practical corroborative check on the traditional DCF. The MTB formula is derived as follows:

Solving for "P" from Equation (1), the standard DCF model, we have

$$P = D/(k-g). \qquad \text{(ii)}$$

But the dividend (D) is equal to the earnings (E) times the earnings payout ratio, or one minus the retention ratio (b), or

$$D = E(1-b). \qquad \text{(iii)}$$

Substituting Equation (iii) into Equation (ii), we have

$$P = \frac{E(1-b)}{k-g} \quad . \qquad \text{(iv)}$$

The earnings (E) are equal to the return on equity (r) times the book value of that equity (B). Making that substitution into Equation (iv), we have

$$P = \frac{rB(1-b)}{k-g} \quad . \qquad \text{(v)}$$

Dividing both sides of Equation (v) by the book value (B) and noting from Equation (iii) in Appendix B that g = br+sv,

$$\frac{P}{B} = \frac{r(1-b)}{k-br-sv} \quad . \qquad \text{(vi)}$$

Finally, solving Equation (vi) for the cost of equity capital (k) yields the MTB formula:

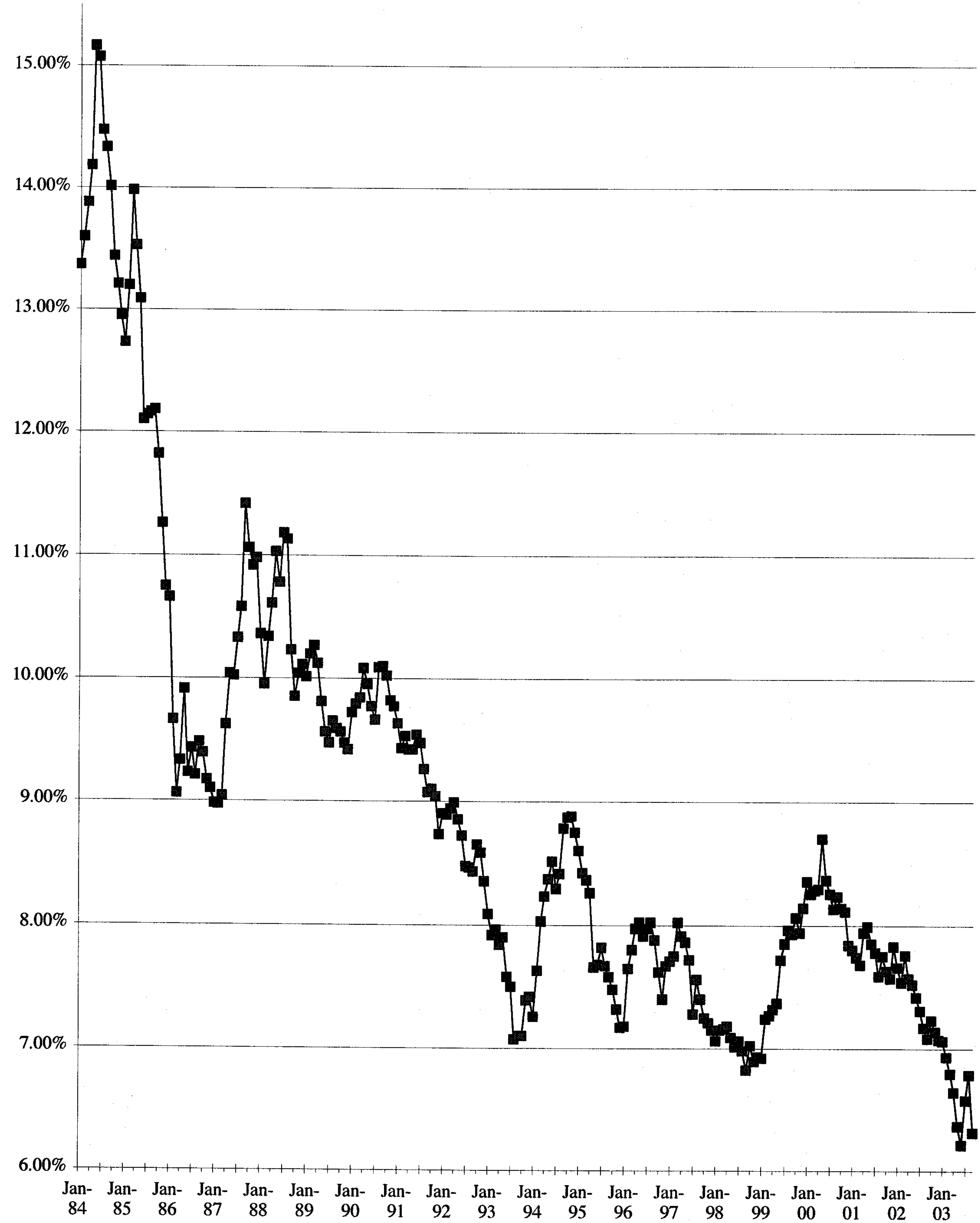
$$k = \frac{r(1-b)}{P/B} + br + sv. \qquad \text{(vii)}$$

Equation (vii) indicates that the cost of equity capital equals the expected return on equity multiplied by the payout ratio, divided by the market-to-book ratio plus growth. Schedule 11 shows the results of applying Equation (vii) to the defined parameters for the electric utility firms in the comparable sample. Page 1 of Schedule 11 utilizes current year (2003) data for the MTB analysis while Page 2 of Schedule 11 utilizes Value Line's 2006-2008 projections.

The MTB cost of equity for the entire sample of electric utility firms, adjusted for a current average market-to-book ratio of 1.67 is 9.59% using the current year data and 9.30% using projected three- to five-year data.

ARIZONA PUBLIC SERVICE COMPANY

Moody's A-Rated Utility Bond Yields

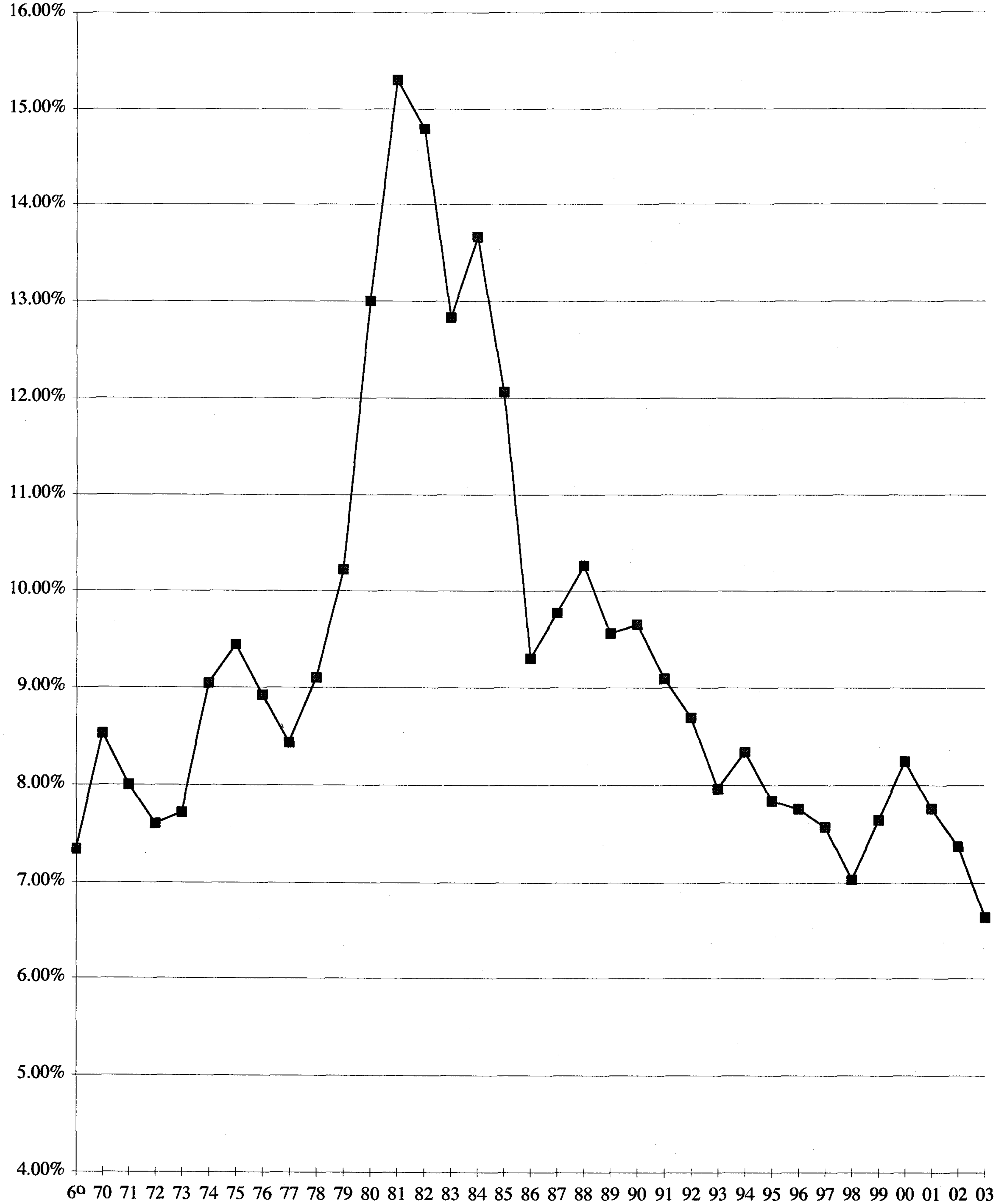


All data from Mergent (Moody's) Bond Record.

ARIZONA PUBLIC SERVICE COMPANY

Moody's A-rated Utility Bond Yields

1969-2003



All data from Moody's.

ARIZONA PUBLIC SERVICE COMPANY
HISTORICAL CAPITAL STRUCTURE

AMOUNT (000)

Type of Capital	Sep-02	Dec-02	Mar-03	Jun-03	Sep-03	5 Quarter Average	June/Sept. Average
Common Equity	$2,237,790	$2,159,312	$2,139,364	$2,155,473	$2,210,965	**$2,180,581**	**$2,183,219**
Long-term Debt	$2,201,156	$2,220,843	$2,222,045	$2,684,044	$2,622,717	**$2,390,161**	**$2,653,381**
Short-term Debt	$25,300	$0	$0	$0	$0	**$5,060**	**$0**
TOTAL	$4,464,246	$4,380,155	$4,361,409	$4,839,517	$4,833,682	**$4,575,802**	**$4,836,600**

PERCENTAGE

Type of Capital	Sep-02	Dec-02	Mar-03	Jun-03	Sep-03	5 Quarter Average	June/Sept. Average
Common Equity	50.13%	49.30%	49.05%	44.54%	45.74%	**47.65%**	**45.14%**
Long-term Debt	49.31%	50.70%	50.95%	55.46%	54.26%	**52.23%**	**54.86%**
Short-term Debt	0.57%	0.00%	0.00%	0.00%	0.00%	**0.11%**	**0.00%**
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**	**100.00%**

Data from company response to RUCO-1.1, Third Quarter 2003 S.E.C. Form 10-Q.

ARIZONA PUBLIC SERVICE COMPANY
PINNACLE WEST CAPITAL CORPORATION
HISTORICALCAPITAL STRUCTURE

AMOUNT (000)

Type of Capital	Sep-02	Dec-02	Mar-03	Jun-03	Sep-03	**Average**
Common Equity	$2,662,530	$2,686,153	$2,658,706	$2,737,228	$2,803,376	**$2,709,599**
Long-term Debt	$3,139,358	$3,162,718	$3,130,243	$3,368,712	$3,289,880	**$3,218,182**
Short-term Debt	$317,811	$102,183	$207,667	$65,802	$90,011	**$156,695**
TOTAL	$6,119,699	$5,951,054	$5,996,616	$6,171,742	$6,183,267	**$6,084,476**

PERCENTAGE

Type of Capital	Sep-02	Dec-02	Mar-03	Jun-03	Sep-03	**Average**
Common Equity	43.51%	45.14%	44.34%	44.35%	45.34%	**44.53%**
Long-term Debt	51.30%	53.15%	52.20%	54.58%	53.21%	**52.89%**
Short-term Debt	5.19%	1.72%	3.46%	1.07%	1.46%	**2.58%**
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Data from company response to RUCO-1.1, Third Quarter 2003 S.E.C. Form 10-Q.

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC UTILITY INDUSTRY COMMON EQUITY RATIOS

ELECTRIC COMPANIES	EQUITY RATIO
ALLETE	54%
American Electric Power	39%
Black Hills Corp.	44%
Central Vermont P.S.	54%
Cleco Corporation	30%
DPL, Inc.	26%
DQE, Inc.	27%
Edison International	22%
El Paso Electric Co.	44%
Empire District Electric	41%
FirstEnergy Corp.	33%
FPL Group	42%
Great Plains Energy	40%
Green Mountain Power	47%
Hawaiian Electric Industries	25%
IDACORP	42%
Maine & Maritimes Corp.	59%
OGE Energy	36%
Otter Tail Power	49%
Pinnacle West Capital Corp.	44%
Progress Energy Inc.	38%
Southern Co.	39%
UIL Holdings	48%
Westar Energy	26%
AVERAGE	**40%**
Investment Grade Average	40%

COMBINATION GAS & ELECTRIC COMPANIES	EQUITY RATIO
AES Corp.	1%
Allegheny Energy	55%
Alliant Energy	38%
Ameren Corp.	45%
Aquilla	35%
Avista Corp.	40%
CenterPoint Energy	11%
CH Energy Group	61%
CINergy Crop.	41%
CMS Energy Corp.	14%
Consolidated Edison	48%
Constellation Energy	39%
Dominion Resources	39%
DTE Energy Company	36%
Duke Energy	38%
Dynegy	19%
Energy East Corp.	36%
Entergy Corp.	50%
Excelon Corp.	34%
Florida Pub. Utilities	44%
MDU Resources	58%
MGE Resources	50%
NiSource Inc.	38%
Northeast Utilities	33%
NSTAR	37%
Pepco Holdings	31%
PG&E Corp.	24%
PNM Resources	48%
PPL Corp.	27%
Public Service Ent. Group	24%
Puget Energy	92%
SCANA Corp.	38%
SEMPRA Energy	36%
Sierra Pacific Resources	24%
TECO Energy	25%
TXU Corp.	27%
Unitil Corp.	33%
Unisource Energy	20%
Vectren Corp.	40%
Wisconsin Energy Corp.	35%
WPS Resources	44%
Xcel Energy Inc.	39%
AVERAGE	**37%**
Investement Grade Average	39%

Data from C.A. Turners Utility Reports, November 2003.

ARIZONA PUBLIC SERVICE COMPANY
EQUITY RATIO OF ELECTRIC UTILITY SAMPLE GROUPS

OLSON

COMPANY	COMMON EQUITY RATIO
CINergy	41.00%
IDACORP	42.00%
OGE Energy	36.00%
PPL Corp.	27.00%
Progress Energy	38.00%
P.S. Ent. Group	24.00%
Pinnacle West Capital Corp.	44.00%
AVERAGE	**36.00%**
MEDIAN	**38.00%**

HILL

COMPANY	COMMON EQUITY RATIO
Central Vermont Public Service	54.00%
Energy East Corp.	36.00%
FirstEnergy Corp.	33.00%
Southern Company	39.00%
Ameren Corp.	45.00%
Cleco Corp.	30.00%
DPL Inc.	26.00%
Empire District Electric	41.00%
Entergy Corp.	50.00%
Great Plains Energy	40.00%
Hawaiian Electric	25.00%
Pinnacle West Capital Corp.	44.00%
AVERAGE	**38.58%**
MEDIAN	**39.50%**

ARIZONA PUBLIC SERVICE COMPANY
SHORT-TERM DEBT

	PINNACLE WEST			ARIZONA PUBLIC SERVICE	
DATE	AMOUNT	COST RATE	DATE	AMOUNT	COST RATE
Jan-01	$44,608,333	7.70%	Jan-01	$44,608,333	7.70%
Feb-01	$77,495,000	0.07%	Feb-01	$17,495,000	7.51%
Mar-01	$118,041,667	6.56%	Mar-01	$35,608,333	6.56%
Apr-01	$137,711,667	5.82%	Apr-01	$97,411,667	5.60%
May-01	$183,485,033	4.66%	May-01	$84,468,667	4.81%
Jun-01	$217,783,333	4.35%	Jun-01	$101,908,333	4.45%
Jul-01	$273,751,533	4.12%	Jul-01	$108,160,000	4.23%
Aug-01	$74,275,000	4.17%	Aug-01	$66,326,667	4.19%
Sep-01	$120,385,000	3.67%	Sep-01	$114,480,000	3.68%
Oct-01	$79,105,000	3.28%	Oct-01	$17,843,333	4.44%
Nov-01	$202,378,667	2.75%	Nov-01	$0	0.00%
Dec-01	$293,425,233	2.92%	Dec-01	$94,197,733	3.16%
Jan-02	$423,833,833	2.44%	Jan-02	$161,791,967	2.39%
Feb-02	$353,629,845	2.36%	Feb-02	$156,663,333	2.32%
Mar-02	$103,095,589	2.49%	Mar-02	$31,126,667	3.01%
Apr-02	$167,110,356	2.36%	Apr-02	$4,083,333	8.21%
May-02	$219,855,834	2.22%	May-02	$55,548,333	2.42%
Jun-02	$294,859,482	2.17%	Jun-02	$132,009,400	2.16%
Jul-02	$352,592,110	2.10%	Jul-02	$144,716,667	2.11%
Aug-02	$314,406,627	2.11%	Aug-02	$57,576,667	2.32%
Sep-02	$319,818,817	2.25%	Sep-02	$9,776,667	4.49%
Oct-02	$297,242,960	1.86%	Oct-02	$990,000	2.00%
Nov-02	$190,971,117	2.28%	Nov-02	$4,567,667	2.99%
Dec-02	$202,781,560	1.99%	Dec-02	$13,023,333	2.63%
Jan-03	$180,781,360	2.22%	Jan-03	$0	0.00%
Feb-03	$149,104,330	1.89%	Feb-03	$0	0.00%
Mar-03	$229,855,293	1.86%	Mar-03	$0	0.00%
Apr-03	$226,767,360	1.96%	Apr-03	$0	0.00%
May-03	$191,334,007	2.19%	May-03	$0	0.00%
Jun-03	$45,547,383	2.29%	Jun-03	$0	0.00%
Jul-03	$72,724,327	1.42%	Jul-03	$0	0.00%
Aug-03	$65,367,877	1.43%	Aug-03	$0	0.00%
2003 AVERAGE	$145,185,242	1.91%	2003 AVERAGE	$0	0.00%
TWO-YEAR AVERAGE	$212,373,915	2.27%	TWO-YEAR AVERAGE	$41,599,796	2.01%
TOTAL PERIOD AVERAGE	$194,503,923	2.87%	TOTAL PERIOD AVERAGE	$48,574,441	2.92%

Data from Company response to RUCO 1.6.

ARIZONA PUBLIC SERVICE COMPANY
RATEMAKNG CAPITAL STRUCTURE

Type of Capital	AMOUNT [000]	PERCENT	COST RATE*	WT. AVG. COST RATE
Common Equity	$2,183,219	45.14%	-	-
Long-term Debt	$2,603,381	53.83%	5.77%	3.11%
Short-term Debt	$50,000	1.03%	3.00%	0.03%
TOTAL CAPITAL	$4,836,600	100.00%		-

*Data from Company response to RUCO 1-2, embedded debt cost at 6/30/03.
Most recent cost of short-term debt for PWCC = 1.43%, use 3.00% for ratemaking purposes.

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC UTILITY SAMPLE GROUP SELECTION

	Company Name	Revenues % Electric	Pending Merger?	Recent Div. Cut?	Generation Assets?	Stable Book Value?	Bond Rating S&P	Bond Rating Moody's	Select
	SCREEN	≥70	no	no	yes	yes	A+ to BBB		
EAST									
e+g	Alegheny Energy	58	no	yes	yes	no	B+	Baa1	
e+g	CH Energy	57	no	no	yes	yes	A	A2	
e	Central Vermont P. S.	100	no	no	yes	yes	BBB+	-	√
e+g	Consolidated Edison	70	no	no	no	yes	A	A1	
e+g	Constellation Energy	26	no	yes	yes	yes	A	A1	
e	DQE, Inc.	88	no	yes	no	no	BBB-	Baa1	
e+g	Dominion Resources	43	no	no	yes	yes	A-	A2	
e+g	Duke Energy	25	no	no	yes	no	BBB+	Baa2	
e+g	Energy East Corp.	72	no	no	yes	yes	BBB+	A3	√
e+g	Excelon Corp.	67	no	no	yes	no	A	A2	
e	FPL Group	86	no	no	yes	yes	A	Aa3	
e	FirstEnergy Corp.	78	no	no	yes	yes	BBB	A3	√
e	Green Mountain Power	100	no	yes	yes	no	BBB	Baa1	
e+g	Northeast Utilities	68	no	yes	yes	yes	A-	A3	
e+g	NSTAR	82	no	no	no	yes	A	A1	
e+g	PPL Corporation	68	no	yes	yes	no	A-	Baa1	
e+g	Pepco Holdings, Inc.	52	no	yes	yes	no	A-	A2	
e	Progress Energy	81	yes	no	yes	yes	BBB	A2	
e+g	Public Service Ent. Gp.	57	no	no	yes	yes	A-	A3	
e+g	SCANA Corp.	43	no	no	yes	yes	A-	A1	
e	Southern Company	82	no	no	yes	yes	A+	A1	√
e+g	TECO Energy	56	no	no	yes	yes	BBB-	A3	
e	UIL Holdings Corp.	64	no	no	no	yes	-	A3	
CENTRAL									
e	ALLETE	33	no	no	yes	yes	A	Baa1	
e+g	Alliant Energy	64	no	no	yes	yes	A	A2	
e+g	Ameren Corp.	88	no	no	yes	yes	A-	A1	√
e	American Eelectric Power	35	no	no	yes	yes	BBB	A3	
e+g	Aquila, Inc.	45	no	yes	yes	yes	B	B3	
e+g	CMS Energy Corp.	9	no	yes	yes	no	BBB-	Baa3	
e+g	CenterPoint Energy	25	no	yes	yes	no	BBB	Baa2	
e+g	Cinergy Corp.	62	no	no	yes	yes	BBB+	A3	
e	Cleco Corporation	77	no	no	yes	yes	BBB+	A3	√
e	DPL Inc.	99	no	no	yes	no	BBB	Baa1	√
e+g	DTE Energy	19	no	no	yes	yes	A-	A2	
e	Empire District Electric	94	no	no	yes	yes	BBB	Baa1	√
e+g	Entergy Corp.	81	no	no	yes	yes	BBB	Baa2	√
e	Great Plains Energy	52	no	no	yes	yes	BBB	A1	√
e+g	MGE Energy	61	no	no	yes	yes	AA-	Aa3	
e+g	NiSource Inc.	14	no	yes	yes	yes	BBB	Baa2	
e	OGE Energy Corp.	44	no	no	yes	yes	BBB+	Baa2	
e	Otter Tail Corp.	43	no	no	yes	yes	A-	A2	
e+g	TXU Corp.	24	no	no	no	yes	BBB	Baa2	
e+g	Vectren Corp.	71	no	no	yes	no	A-	A3	
e+g	WPS Resources	22	no	no	yes	yes	AA-	Aa1	
e	Westar Energy	84	no	yes	yes	no	BBB-	Ba1	
e+g	Wisconsisn Energy	49	no	yes	yes	yes	A-	Aa2	
WEST									
e+g	Avista Corp.	90	no	yes	yes	no	BBB-	Baa3	
e	Black Hills Corp.	21	no	no	yes	yes	BBB	Baa1	
e	Edison International	74	no	yes	yes	no	BB	Ba2	
e	El Paso Electric	99	no	yes	yes	yes	BBB-	Baa3	
e	Hawaiian Electric	78	no	no	yes	yes	BBB+	Baa1	√
e	IDACORP, Inc.	92	no	yes	yes	yes	A	A2	
e+g	MDU Resources Group	8	no	no	yes	yes	A-	A2	
e+g	PG&E Corp.	65	yes	yes	yes	no	CC	B1	
e+g	PNM Resources	74	no	no	yes	yes	BBB-	Baa3	
e	Pinnacle West Capital	70	no	no	yes	yes	A-	A3	√
e+g	Puget Energy, Inc.	62	no	yes	yes	yes	BBB	Baa2	
e+g	Sempra Energy	45	no	yes	yes	yes	A+	A1	
e+g	Sierra Pacific Resources	94	no	yes	yes	no	BB	Ba2	
e+g	UniSource Energy	95	no	yes	yes	yes	BBB-	Ba2	
e+g	Xcel Energy, Inc.	58	no	yes	yes	yes	BBB+	A3	

e= electric company; e+g=combination electric and gas company

Data from Value Line Ratings & Reports, September 5, October 3, November 14, 2003; CA Turner's Utility Reports November 2003

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS
INSURANCE COMPANIES

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
CV	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	-3.8889	01.1%	-4.28%	15.63	11.46	
1999	0.3125	08.0%	2.50%	16.05	11.47	
2000	0.2281	06.9%	1.57%	16.57	11.51	
2001	0.0538	05.8%	0.31%	15.81	11.61	
2002	0.4286	09.3%	3.99%	16.83	11.74	
AVERAGE GROWTH			0.82%	0.50%		0.61%
2003	0.4133	08.5%	3.51%		12.00	2.21%
2004	0.4065	09.0%	3.66%		12.00	-0.50%
2006-2008	0.4378	10.5%	4.60%	2.00%	12.10	0.61%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
EAS	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.4834	11.3%	5.46%	13.61	125.89	
1999	0.5602	15.8%	8.85%	12.84	109.34	
2000	0.5749	13.8%	7.93%	14.59	117.66	
2001	0.5400	13.1%	7.07%	15.26	116.72	
2002	0.3600	08.0%	2.88%	16.97	144.97	
AVERAGE GROWTH			6.44%	4.00%		3.59%
2003	0.4118	09.5%	3.91%		146.00	0.71%
2004	0.4057	09.5%	3.85%		147.00	0.70%
2006-2008	0.4200	09.5%	3.99%	5.00%	150.00	0.68%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
FE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.2308	09.9%	2.28%	18.77	237.07	
1999	0.4000	12.5%	5.00%	19.63	232.45	
2000	0.4424	12.9%	5.71%	20.72	224.53	
2001	0.4718	08.9%	4.20%	24.86	297.64	
2002	0.4094	10.5%	4.30%	23.92	297.64	
AVERAGE GROWTH			4.30%	6.50%		5.85%
2003	0.2105	07.5%	1.58%		315.00	5.83%
2004	0.4545	10.5%	4.77%		315.00	2.87%
2006-2008	0.4333	10.0%	4.33%	4.50%	315.00	1.14%

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
SO	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.2254	12.2%	2.75%	14.02	698.63	
1999	0.2678	13.6%	3.64%	13.82	666.00	
2000	0.3333	12.3%	4.10%	15.67	682.00	
2001	0.1677	14.0%	2.35%	11.42	699.00	
2002	0.2649	15.1%	4.00%	12.15	716.00	
AVERAGE GROWTH			3.37%	-1.00%		0.62%
2003	0.2486	14.0%	3.48%		730.00	1.96%
2004	0.2718	14.5%	3.94%		740.00	1.66%
2006-2008	0.3277	15.5%	5.08%	5.00%	770.00	1.46%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
AEE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.0993	12.6%	1.25%	22.27	137.22	
1999	0.0961	12.5%	1.20%	22.52	137.22	
2000	0.2372	14.3%	3.39%	23.30	137.22	
2001	0.2551	14.0%	3.57%	24.26	138.05	
2002	0.0451	09.9%	0.45%	24.93	154.10	
AVERAGE GROWTH			1.97%	1.50%		2.94%
2003	0.1241	11.0%	1.37%		163.00	5.78%
2004	0.1533	11.0%	1.69%		164.80	3.41%
2006-2008	0.2061	11.0%	2.27%	3.50%	170.20	2.01%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
CNL	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.2768	12.7%	3.52%	9.07	44.97	
1999	0.3025	12.9%	3.90%	9.44	44.88	
2000	0.4178	14.9%	6.23%	10.04	44.99	
2001	0.4238	14.6%	6.19%	10.69	44.96	
2002	0.4079	13.1%	5.34%	11.77	47.04	
AVERAGE GROWTH			5.03%	5.50%		1.13%
2003	0.3077	12.5%	3.85%		47.35	0.66%
2004	0.3571	13.0%	4.64%		47.65	0.65%
2006-2008	0.4000	12.5%	5.00%	3.00%	48.50	0.61%

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
DPL	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.2419	13.6%	3.29%	8.58	161.26	
1999	0.3037	14.0%	4.25%	9.20	157.80	
2000	0.3691	22.9%	8.45%	6.80	127.77	
2001	0.4598	27.8%	12.78%	6.31	126.50	
2002	-0.3056	10.8%	-3.30%	6.38	126.50	
AVERAGE GROWTH			5.10%	-3.00%		-5.89%
2003	0.2480	17.5%	4.34%		126.50	0.00%
2004	0.2769	17.5%	4.85%		126.50	0.00%
2006-2008	0.4703	19.5%	9.17%	6.00%	126.50	0.00%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
EDE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.1634	11.3%	1.85%	13.43	17.11	
1999	-0.1327	08.8%	-1.17%	13.48	17.37	
2000	0.0519	09.8%	0.51%	13.65	17.60	
2001	-1.1695	03.9%	-4.56%	13.58	19.76	
2002	-0.0756	07.8%	-0.59%	14.59	22.57	
AVERAGE GROWTH			-0.79%	1.50%		7.17%
2003	0.1467	10.0%	1.47%		23.00	1.91%
2004	0.1467	09.5%	1.39%		23.20	1.39%
2006-2008	0.2686	10.5%	2.82%	3.00%	23.80	1.07%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
ETR	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.3243	07.4%	2.40%	28.79	246.83	
1999	0.4667	07.7%	3.59%	28.81	247.08	
2000	0.5892	09.7%	5.72%	31.89	219.60	
2001	0.5844	09.3%	5.44%	33.78	220.73	
2002	0.6359	10.9%	6.93%	35.24	222.42	
AVERAGE GROWTH			4.81%	3.50%		-2.57%
2003	0.6145	11.0%	6.76%		228.40	2.69%
2004	0.5614	10.0%	5.61%		229.00	1.47%
2006-2008	0.5422	09.5%	5.15%	6.50%	230.80	0.74%

ARIZONA PUBLIC SERVICE COMPANY
DCF GROWTH RATE PARAMETERS

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
GXP	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.1323	13.1%	1.73%	14.41	61.91	
1999	-0.3175	09.0%	-2.86%	13.97	61.91	
2000	0.1902	13.8%	2.63%	14.88	61.91	
2001	-0.0440	12.6%	-0.55%	12.59	61.91	
2002	0.1863	13.6%	2.53%	13.58	69.20	
AVERAGE GROWTH			0.70%	-1.00%		2.82%
2003	0.1902	14.5%	2.76%		69.20	0.00%
2004	0.2279	14.5%	3.30%		69.20	0.00%
2006-2008	0.3200	15.0%	4.80%	3.50%	69.20	0.00%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
HE	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.1622	11.4%	1.85%	25.75	32.12	
1999	0.1419	11.0%	1.56%	26.31	32.21	
2000	0.0236	09.8%	0.23%	25.43	32.99	
2001	0.2226	11.6%	2.58%	26.11	35.60	
2002	0.2346	11.3%	2.65%	28.43	36.81	
AVERAGE GROWTH			1.77%	1.50%		3.47%
2003	0.1143	09.5%	1.09%		38.00	3.23%
2004	0.1298	09.5%	1.23%		38.25	1.94%
2006-2008	0.1733	09.0%	1.56%	3.50%	39.00	1.16%

COMPANY	INTERNAL GROWTH				EXTERNAL GROWTH	
PNW	RETENTION RATIO	EQUITY RETURN	"g"	BOOK VALUE ($/SHARE)	SHARES OUTST (MILLIONS)	SHARE GROWTH
1998	0.5684	11.2%	6.37%	25.50	84.83	
1999	0.5818	12.2%	7.10%	26.00	84.83	
2000	0.5731	11.9%	6.82%	28.09	84.83	
2001	0.5842	12.5%	7.30%	29.46	84.83	
2002	0.3557	08.0%	2.85%	29.44	91.26	
AVERAGE GROWTH			6.09%	5.00%		1.84%
2003	0.3216	08.5%	2.73%		91.30	0.04%
2004	0.3900	09.5%	3.71%		91.30	0.02%
2006-2008	0.3545	09.5%	3.37%	3.00%	91.30	0.01%

Data from Value Line Ratings & Reports Sept. 5, oct. 3, Nov. 14, 2003.

ARIZONA PUBLIC SERVICE COMPANY

DCF GROWTH RATES

COMPANY	br	+	sv=g*((M/B+1)/2-1)	=	g
CV	4.75%	+	0.60% ((1.36 + 1)/2-1)	=	4.86%
EAS	4.50%	+	1.00% ((1.28 + 1)/2-1)	=	4.64%
FE	4.50%	+	2.00% ((1.38 + 1)/2-1)	=	4.88%
SO	5.00%	+	1.25% ((2.29 + 1)/2-1)	=	5.81%
AEE	3.00%	+	2.50% ((1.67 + 1)/2-1)	=	3.84%
CNL	4.75%	+	0.75% ((1.62 + 1)/2-1)	=	4.98%
DPL	5.75%	+	0.00% ((2.72 + 1)/2-1)	=	5.75%
EDE	3.50%	+	2.50% ((1.45 + 1)/2-1)	=	4.06%
ETR	6.00%	+	0.25% ((1.40 + 1)/2-1)	=	6.05%
GXP	4.25%	+	0.50% ((2.24 + 1)/2-1)	=	4.56%
HE	3.00%	+	2.25% ((1.50 + 1)/2-1)	=	3.56%
PNW	4.50%	+	0.50% ((1.18 + 1)/2-1)	=	4.54%

Average Market-to-Book Ratio = 1.67

CV	=	Central Vermont Public Service
EAS	=	Energy East Corp.
FE	=	FirstEnergy Corp.
SO	=	Southern Company
AEE	=	Ameren Corp.
CNL	=	Cleco Corp.
DPL	=	DPL Inc.
EDE	=	Empire District Electric
ETR	=	Entergy Corp.
GXP	=	Great Plains Energy
HE	=	Hawaiian Electric
PNW	=	Pinnacle West Capital Corp.

g*= expected growth in number of shares outstanding

ARIZONA PUBLIC SERVICE COMPANY

GROWTH RATE COMPARISON

COMPANY	br + sv	Value Line Projected EPS	Value Line Projected DPS	Value Line Projected BVPS	Zack's EPS	Value Line Historic EPS	Value Line Historic DPS	Value Line Historic BVPS	Zack's & VL AVGS.	5-yr Compound Hist. EPS	5-yr Compound Hist. DPS	5-yr Compound Hist. BVPS
CV	4.86%	7.50%	3.00%	2.00%	n/a	-3.00%	1.00%	0.50%	1.83%	52.81%	0.00%	1.81%
EAS	4.64%	1.00%	4.00%	5.00%	5.00%	8.00%	5.50%	4.00%	4.64%	2.40%	5.09%	5.40%
FE	4.88%	2.00%	2.00%	4.50%	6.00%	6.00%	0.00%	6.50%	3.86%	-0.52%	0.00%	5.73%
SO	5.81%	6.50%	3.00%	5.00%	4.60%	2.00%	1.50%	-1.00%	3.09%	1.35%	0.74%	-1.65%
AEE	3.84%	1.00%	0.50%	3.50%	2.90%	2.50%	0.50%	1.50%	1.77%	0.56%	0.00%	3.42%
CNL	4.98%	0.00%	0.50%	3.00%	n/a	6.50%	2.50%	5.50%	3.00%	3.03%	2.13%	2.77%
DPL	5.75%	6.00%	0.50%	6.00%	4.50%	3.00%	1.50%	-3.00%	2.64%	0.16%	0.00%	-4.40%
EDE	4.06%	9.00%	0.00%	3.00%	10.00%	-3.50%	0.00%	1.50%	2.86%	-0.40%	0.00%	2.17%
ETR	6.05%	5.50%	8.50%	6.50%	6.10%	7.00%	-6.50%	3.50%	4.37%	13.33%	1.30%	5.85%
GXP	4.56%	4.50%	0.50%	3.50%	4.00%	1.50%	1.00%	-1.00%	2.00%	1.64%	0.24%	-0.36%
HE	3.56%	0.00%	0.00%	3.50%	2.90%	2.50%	0.50%	1.50%	1.56%	-1.11%	0.00%	2.51%
PNW	4.54%	0.50%	5.50%	3.00%	5.30%	5.00%	8.50%	5.00%	4.69%	-2.20%	7.06%	3.48%
		3.63%	2.33%	4.04%		3.13%	1.33%	2.04%		5.92%	1.38%	2.23%
AVERAGES	4.79%		3.33%		5.13%		2.17%		3.03%		3.18%	

Thomson Financial (IBES) 5-year earnings growth projections: CV-n/a; EAS- 4.0%; FE-4.0%; SO-5.0%; AEE-3.0%, CNL-n/a; DPL-4.0%; EDE-3.0%; ETR-6.0%, GXP-4.0%; HE-2.8%; PNW-5.0%. Average = 4.08%.

Exhibit_(SGH-1)
Schedule 6

ARIZONA PUBLIC SERVICE COMPANY

STOCK PRICE, DIVIDENDS, YIELDS

COMPANY	AVG. STOCK PRICE 11/21/02-1/3/03 (PER SHARE)		ANNUALIZED DIVIDEND (PER SHARE)		DIVIDEND YIELD
CV	$23.28	*	$0.92		3.96%
EAS	$22.65	*	$1.05		4.62%
FE	$34.11		$1.50		4.40%
SO	$29.55		$1.40		4.74%
AEE	$44.11		$2.54		5.76%
CNL	$16.86		$0.90		5.34%
DPL	$18.62		$0.94		5.05%
EDE	$21.68		$1.28		5.90%
ETR	$53.69		$1.80		3.35%
GXP	$31.76		$1.66		5.23%
HE	$45.14		$2.48		5.49%
PNW	$37.02		$1.80		4.86%
				AVERAGE	**4.89%**

*Dividend increase expected in next quarter. Current dividend multiplied by (1+g), from Schedule 5.

ARIZONA PUBLIC SERVICE COMPANY

DCF COST OF EQUITY CAPITAL

COMPANY	DIVIDEND YIELD Schedule 6	GROWTH RATE Schedule 5	DCF COST OF EQUITY CAPITAL
CV	3.96%	4.86%	8.82%
EAS	4.62%	4.64%	9.26%
FE	4.40%	4.88%	9.27%
SO	4.74%	5.81%	10.54%
AEE	5.76%	3.84%	9.60%
CNL	5.34%	4.98%	10.32%
DPL	5.05%	5.75%	10.80%
EDE	5.90%	4.06%	9.97%
ETR	3.35%	6.05%	9.40%
GXP	5.23%	4.56%	9.79%
HE	5.49%	3.56%	9.06%
PNW	4.86%	4.54%	9.41%
		AVERAGE	**9.69%**
		STANDARD DEVIATION	**0.61%**

ARIZONA PUBLIC SERVICE COMPANY

CAPM COST OF EQUITY CAPITAL

k = rf + B (rm - rf)

T-BILLS

[rf]* = 0.94%
[rm - rf]† = 6.40% (geometric mean)
[rm - rf]† = 8.40% (arithmetic mean)
average beta = 0.67

k = 0.94% + 0.67 (6.4%/8.40%)
k = 0.94% + 4.29%/5.64%
k = 5.23% / 6.58%

T-BONDS

[rf]* = 5.18%
[rm - rf]† = 4.70% (geometric mean)
[rm - rf]† = 6.40% (arithmetic mean)
average beta = 0.67

k = 5.18% + 0.67 (5.40%/7.00%)
k = 5.18% + 3.15%/4.29%
k = 8.33% / 9.47%

*Current T-Bill & T-Bond yields, six-week avg. yield from Value Line Selection & Opinion (10/24/03-11/28/03)
†Geometric and arithmetic market risk premiums from Ibbotson Associates 2003 SBBI Yearbook, p. 28.

ARIZONA PUBLIC SERVICE COMPANY

PROOF

If book value exceeds market price,
the market-to-book ratio is less than 1.0,
and the earnings-price ratio exceeds the cost of capital.

MP = market price
BV = book value
i = cost of equity capital
r = earned return
E = earnings

1. At MP = BV, $i = r = \frac{E}{MP}$.

2. E = rBV.

3. Then, $\frac{E}{MP} = \frac{rBV}{MP}$.

4. When BV > MP, i.e., $\frac{BV}{MP} > 1$, then,

   a. $\frac{E}{MP} > r$, since $\frac{E}{MP} = \frac{rBV}{MP} > r$, because $\frac{BV}{MP} > 1$;

   b. $i > r$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} > 1$, then $i > r$; and

   c. $\frac{E}{MP} > i$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} > 1$, then $\frac{E}{MP} > i$, because,

      1) $\frac{BV}{MP} > 1$, through MP decreasing, and, if so, $\frac{E}{MP}$ increases, therefore, $\frac{E}{MP} > i$, or

      2) $\frac{BV}{MP} > 1$, through BV increasing, and, if so, given E = rBV, $\frac{E}{MP}$ increases, therefore, $\frac{E}{MP} > i$.

5. Ergo, $\frac{E}{MP} > i > r$, the cost of capital exceeds the earned return.

ARIZONA PUBLIC SERVICE COMPANY

MODIFIED EARNINGS-PRICE RATIO ANALYSIS

COMPANY	Zack's Projected 2004 Earnings (Per Share)	Market Price (Per share)	Earnings-Price Ratio		Current R.O.E. 2003	Projected R.O.E. 2006-2008
CV	$1.55	$23.28	6.66%		8.50%	10.50%
EAS	$1.73	$22.65	7.64%		9.50%	9.50%
FE	$2.91	$34.11	8.53%		7.50%	10.00%
SO	$1.97	$29.55	6.67%		14.00%	15.50%
AEE	$2.98	$44.11	6.76%		11.00%	11.00%
CNL	$1.15	$16.86	6.82%		12.50%	12.50%
DPL	$1.32	$18.62	7.09%		17.50%	19.50%
EDE	$1.37	$21.68	6.32%		10.00%	10.50%
ETR	$4.22	$53.69	7.86%		11.00%	9.50%
GXP	$2.07	$31.76	6.52%		14.50%	15.00%
HE	$3.11	$45.14	6.89%		9.50%	9.00%
PNW	$2.96	$37.02	7.99%		8.50%	9.50%
		AVERAGE	7.14%		11.17%	
		CURRENT M.E.P.R.		**9.16%**		
		AVERAGE	7.14%			11.83%
		PROJECTED M.E.P.R.			**9.49%**	

ARIZONA PUBLIC SERVICE COMPANY

MARKET-TO-BOOK RATIO ANALYSIS

k = R.O.E.(1-b)/(M/B) + g
[2002]

COMPANY									MARKET-TO-BOOK COST OF EQUITY
CV	k= 08.5%	(1-	0.4133	)/	1.36	+	4.86%	=	8.52%
EAS	k= 09.5%	(1-	0.4118	)/	1.28	+	4.64%	=	9.01%
FE	k= 07.5%	(1-	0.2105	)/	1.38	+	4.88%	=	9.18%
SO	k= 14.0%	(1-	0.2486	)/	2.29	+	5.81%	=	10.40%
AEE	k= 11.0%	(1-	0.1241	)/	1.67	+	3.84%	=	9.60%
CNL	k= 12.5%	(1-	0.3077	)/	1.62	+	4.98%	=	10.32%
DPL	k= 17.5%	(1-	0.2480	)/	2.72	+	5.75%	=	10.59%
EDE	k= 10.0%	(1-	0.1467	)/	1.45	+	4.06%	=	9.95%
ETR	k= 11.0%	(1-	0.6145	)/	1.40	+	6.05%	=	9.07%
GXP	k= 14.5%	(1-	0.1902	)/	2.24	+	4.56%	=	9.79%
HE	k= 09.5%	(1-	0.1143	)/	1.50	+	3.56%	=	9.17%
PNW	k= 08.5%	(1-	0.3216	)/	1.18	+	4.54%	=	9.44%
								AVERAGE	**9.59%**
								STANDARD DEVIATION	**0.64%**

Note: Equity returns and retention ratios based on Value Line current year projections.

ARIZONA PUBLIC SERVICE COMPANY

MARKET-TO-BOOK RATIO ANALYSIS

k = R.O.E.(1-b)/(M/B) + g
[2005-2007]

COMPANY									MARKET-TO-BOOK COST OF EQUITY
CV	k= 10.5%	(1-	0.4378	)/	1.36	+	4.86%	=	9.19%
EAS	k= 09.5%	(1-	0.4200	)/	1.28	+	4.64%	=	8.95%
FE	k= 10.0%	(1-	0.4333	)/	1.38	+	4.88%	=	9.00%
SO	k= 15.5%	(1-	0.3277	)/	2.29	+	5.81%	=	10.36%
AEE	k= 11.0%	(1-	0.2061	)/	1.67	+	3.84%	=	9.06%
CNL	k= 12.5%	(1-	0.4000	)/	1.62	+	4.98%	=	9.61%
DPL	k= 19.5%	(1-	0.4703	)/	2.72	+	5.75%	=	9.55%
EDE	k= 10.5%	(1-	0.2686	)/	1.45	+	4.06%	=	9.36%
ETR	k= 09.5%	(1-	0.5422	)/	1.40	+	6.05%	=	9.15%
GXP	k= 15.0%	(1-	0.3200	)/	2.24	+	4.56%	=	9.11%
HE	k= 09.0%	(1-	0.1733	)/	1.50	+	3.56%	=	8.52%
PNW	k= 09.5%	(1-	0.3545	)/	1.18	+	4.54%	=	9.75%
								AVERAGE	**9.30%**
								STANDARD DEVIATION	**0.47%**

Note: Equity returns and retention ratios based on Value Line three- to five-year projections.

ARIZONA PUBLIC SERVICE COMPANY
OVERALL COST OF CAPITAL

Type of Capital	PERCENT	COST RATE	WT. AVG. COST RATE
Common Equity	45.14%	9.50%	4.29%
Long-term Debt	53.83%	5.77%	3.11%
Short-term Debt	1.03%	3.00%	0.03%
TOTAL CAPITAL	100.00%		7.43%

PRE-TAX INTEREST COVERAGE = 3.28X

*Assuming the Company experiences, prospectively, an income tax rate of 40%, the pre-tax overall return would be 10.28% [7.43%-(3.11%+0.03%) = 4.29% /(1-40%) = 7.15%+(3.11%+0.03%)]. That pre-tax overall return, 10.28%, divided by the weighted cost of debt (3.11%+0.03%), indicates a pre-tax interest coverage of 3.28 times.

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 3, 2004

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and your qualifications in the field of utilities regulation.

A. Appendix I, which is attached to this testimony, describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Arizona Public Service Company's ("APS" or "Company") application for a permanent rate increase ("Application"). APS filed the Application with the Arizona Corporation Commission ("ACC" or "Commission") on June 27, 2003. The Company chose the period ended December 31, 2002 as the test year ("Test Year") in this proceeding.

Q. What aspects of the APS Application will you provide direct testimony on?

A. My direct testimony will concentrate on the lead/lag study that was used to develop the Company's recommended level of working capital (included in rate base) and on various operating expense adjustments.

Q. Which other RUCO witnesses will be providing direct testimony in this proceeding?

A. Ms. Marylee Diaz Cortez, C.P.A., the chief of RUCO's Accounting & Rates section, will provide direct testimony on the majority of the rate base issues addressed in the Company's Application and on the operating adjustments proposed by APS that are not addressed in my testimony.

In addition to the direct testimony of Ms. Diaz Cortez, RUCO will also present the testimony of four outside consultants: Dr. Richard Rosen and Dr. John Stutz, both of Tellus Institute, who will address the transmission issues associated with the case, the Company's base cost of fuel, rate design and cost of service; Mr. David A. Schlissel, a senior consultant with Synapse Energy Economics, who will present testimony on the Pinnacle West Energy Corporation ("PWEC") assets; and Mr. Stephen G. Hill, who will address the cost of capital issues associated with the case and will present his recommended rate of return on invested capital which will include his recommended weighted costs of both common equity and debt.

Q. Please describe how you conducted your analysis of the APS Application.

A. I reviewed the APS Application and analyzed various work papers that were provided to RUCO by the Company as part of its initial filing. Other pertinent information and source documents were collected through a series of written data requests, which were faxed and mailed to the Company. After compiling the aforementioned information and materials, I performed an analysis that provided additional insight into the Company's working capital and operating expense proposals. RUCO's recommendations on working capital and the eight operating income adjustments covered in this testimony are based on the results of my analysis.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-7. These schedules exhibit detailed information on RUCO's Rate Base Adjustment #5 and RUCO's Operating Adjustments #8, #9 and #12 through #15 (Operating Adjustments #10 and #11 are explained in my direct testimony). The effects of these specific adjustments on RUCO's recommended levels of rate base and operating income can be viewed in Schedules MDC-2 through MDC-5, which are presented in the direct testimony of RUCO witness Marylee Diaz Cortez.

Q. Does your silence on any of the issues or matters addressed in the Company's Application constitute either your, or RUCO's, acceptance of the Company's position on such issues or matters?

A. No, it does not.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you address in your testimony that pertain to rate base, operating revenue, and operating expense.

A. My testimony will present the following recommended adjustments:

Rate Base Adjustments:

Working Capital – This adjustment reduces cash working capital by $75,439,000. The adjustment reflects the results of RUCO's recalculation of cash working capital using RUCO's adjusted Test Year levels of expense and the exclusion of non-cash items.

Operating Adjustments:

Normalize Payroll – This normalization adjustment reduces the Company-proposed level of payroll expense by $93,000. In making the adjustment, RUCO analyzed payroll data over the 2000 through 2002 operating periods.

Employee Severance – This adjustment decreases the Company's requested level of expense by $6,972,384 as a result of RUCO's use of a ten-year amortization period in the calculation of the expense as opposed to a three-year period used by APS.

Remove Incentive Pay – This adjustment removes $11,056,000 in incentive pay that was awarded to employees under questionable circumstances.

Remove Avnet Software Lease Expense – This adjustment decreases operating expense by $965,000. The adjustment removes a non-recurring expense associated with software that was leased by the Company during the Test Year.

Interest on Customer Deposits – This adjustment decreases the level of interest paid on customer deposits by $354,000. The adjustment reflects RUCO's use of an updated one-year constant maturities rate that APS uses to calculate levels of interest expense on the Company's year-end balance of customer deposits.

Property Taxes – This pro forma adjustment annualizes property tax expense by using the Arizona Department of Revenue ("DOR") approved formula for computing property tax liability. The Adjustment reduces the Company-proposed level of property tax expense by $3,760,000.

Income Taxes – This adjustment calculates the appropriate level of income tax expense given RUCO's recommended operating income.

Schedule 1 Changes – This adjustment reflects the service charge recommendations of RUCO witness Dr. John Stutz. The adjustment reduces electric operating revenues by $62,629.

RATE BASE

Rate Base Adjustment #5 – Working Capital

Q. Is APS requesting that an allowance for cash working capital be included in rate base?

A. Yes.

Q. What methodology has the Company used to calculate the level of cash working capital that it seeks to include in rate base?

A. The Company has used the lead/lag study method as opposed to the formula method (which is generally used for smaller utilities and always produces a positive working capital figure).

Q. Has RUCO analyzed the Company's lead/lag study that was used to compute the level of cash working capital that APS is seeking?

A. Yes.

Q. Does RUCO agree with the Company's computation of cash working capital?

A. No. There are two main areas of disagreement that RUCO has in regard to the way in which the Company has computed its requested level of cash working capital. The first area of disagreement is the Company's decision to include non-cash items in its lead/lag study. This has the effect of increasing the allowance for working capital by $54,097,922. The second area of disagreement is the Company's use of unadjusted Test Year levels of operating expense as opposed to adjusted Test Year levels of expense.

Q. What non-cash items has APS included in the Company's calculation of cash working capital?

A. APS has included such non-cash items as depreciation & amortization expense, the amortization of a plant acquisition adjustment, deferred income taxes and several other non-cash amortized operating expense items.

Q. What has the Commission's position been in regard to the inclusion of non-cash items in the allowance for cash working capital?

A. The ACC has consistently rejected the inclusion of non-cash items in the calculation of cash working capital. The best example of this can be found in Decision No. 56659 dated October 24, 1989, in which the Commission rejected Tucson Electric Power's ("TEP") inclusion of non-cash items in its calculation of cash working capital. In the decision, the Commission states the following:

> "As we have stated in previous decisions, the calculation is for <u>"cash working capital" and not "cash and non-cash working capital"</u> [emphasis included]. Further, we believe the inclusion of equity costs in working capital provides an additional return over and above the cost of equity. As a result, we clearly reject TEP's request to include "non-cash" items in its cash working capital calculation."

The Commission latter affirmed this same position in Decision No. 61110 dated August 28, 1998, in which Vail Water Company also attempted to include non-cash items in its calculation of cash working capital. Given these facts RUCO believes that it is appropriate to exclude the non-cash items noted earlier.

Q. Why does RUCO disagree with the Company's use of unadjusted Test Year levels of operating expense in its calculation of cash working capital?

A. RUCO believes that the level of cash working capital in rate base should include the adjusted Test Year expenses in order to reflect what the Company's cash working capital requirements are on a going-forward basis.

Q. Has RUCO recalculated the Company's cash working capital requirement using adjusted Test Year expense levels and excluding non-cash items?

A. Yes. My recalculation of the Company's cash working capital requirement can be viewed on Page 2 of Schedule WAR-1. Other than the aforementioned changes, the method that I used to calculate RUCO's recommended level of cash working capital is identical to the method used by the Company. RUCO's total working capital adjustment, exhibited on Page 1 of Schedule WAR-1 is a $75,439,000 decrease to the level of cash working capital requested by APS.

OPERATING INCOME

Operating Adjustment #8 – Normalize Payroll

Q. Has RUCO studied the Company's adjustment to the Test Year level of payroll expense?

A. Yes.

Q. Does RUCO agree with the Company's method for annualizing Test Year payroll expense?

A. No. RUCO believes that the Company's method for annualizing payroll is too dependent on payroll levels that were incurred only during the Test Year period.

Q. What method has RUCO used in arriving at its recommended level of payroll expense?

A. RUCO believes that a better approach to normalizing payroll expense is to analyze payroll data over multiple operating periods and then calculate a normalized expense figure that is based on that data.

Q. Has RUCO used this approach in calculating its adjustment to payroll expense?

A. Yes. My adjustment was based on payroll data from the Company's 2000, 2001 and 2002 operating periods. RUCO's recommended reduction of $93,000 to the Company's proposed level of payroll expense is the result of my analysis of the amounts of base, overtime and premium pay, attributable to fuel handling and operations and maintenance expense, that was paid out over the aforementioned three-year period. The adjustment is exhibited in Schedule WAR-2.

Operating Adjustment #9 – Employee Severance

Q. Does RUCO agree with APS' calculation of the Company-proposed pro forma adjustment to employee severance expense?

A. RUCO is satisfied with the overall method that the Company used to calculate its adjustment to Test Year employee severance expense. However, RUCO disagrees with the Company's decision to use a three-year amortization period.

Q. What amortization period is RUCO recommending?

A. RUCO is recommending a ten-year amortization period. This is based on RUCO's belief that current APS ratepayers will not see any benefit from the realized savings of the Company's severance program should the Commission adopt the Company-proposed three-year amortization period.

This is because the annual payroll savings attributable to the severance program would equal the three-year amortization expense.

Q. Does RUCO's adjustment reflect the effects of a ten-year amortization period?

A. Yes. As can be seen in Schedule WAR-3, the only difference between RUCO's calculation and the Company's calculation is RUCO's use of a ten-year amortization period. RUCO's adjustment results in a $6,972,384 reduction in Test Year operating expense. This adjustment will allow today's customers as well as future customers to benefit from the savings attributable to the severance program.

Operating Adjustment #10 – Remove Incentive Pay

Q. Why has RUCO removed $11,056,000 in incentive pay from operating expense?

A. RUCO believes that the removal of the incentive pay is warranted when the circumstances under which the incentive payment was made are taken into consideration.

Q. What were the circumstances surrounding the issuance of the incentive payments?

A. Based on confidential information provided by the Company, APS had instituted a performance incentive pay program that was based on the maximization of earnings levels. Once a specific level of earnings (predetermined by APS as part of the incentive plan's goals) were achieved by APS employees, set amounts of incentive awards, as a percentage of earnings, would be paid out by the Company.

Q. Did the Company's employees reach the goals set forth in the APS incentive plan?

A. No, they did not. The Company stated that even though the employee efforts fell far short of the earnings threshold levels established in the plan, the Company's board of directors elected to pay out a bonus anyway[1]. Given these circumstances, RUCO believes that the payment of bonuses should not be recovered from ratepayers.

Q. Why does RUCO believe that the payment of bonus money, paid out without meeting performance goals, should not be recovered from ratepayers?

A. The original terms of the incentive plan were not achieved by the Company's employees and the ratepayers will not receive any benefit from the level of expense reductions that were originally set by APS. In effect, we have a situation where the Company set goals for its employees that they failed to meet but the Company's board members said hey, that's okay, we'll still give you something anyway. RUCO believes that if the

[1] Company response to Utilitech data request UTI-12-299.

Company wants to make such an incentive payment it should treat the bonus as a below the line expense item. In this case, since employee performance did not reach its goals, there is no incremental benefit that would warrant ratepayers funding of the bonuses.

Operating Adjustment #11 – Remove Avnet Software Lease Expense

Q. Please explain your adjustment, for Avnet software lease expense.

A. The adjustment removes $965,000 in non-recurring software leasing expense. The adjustment was based on information provided by the Company in its response to data requests issued by Utilitech[2].

Operating Adjustment #12 - Interest on Customer Deposits

Q. How does APS calculate interest on customer deposits held by the Company?

A. APS calculates interest on customer deposits by multiplying the year-end customer deposit balance by a one-year treasury constant maturities rate. The one-year constant maturities rate used by the Company is the daily rate that is published in the Federal Reserve's website on the first business day of the New Year. In this proceeding, APS used the customer deposit balance booked on the last day of the Test Year and the one-year constant maturities rate published on January 2, 2003. The

[2] Utilitech data requests UTI 4-158 and UTI 10-266.

Company stated in its Application that this is the same method that has been used by the Commission in prior rate case proceedings.

Q. Has RUCO made an adjustment for interest on customer deposits?

A. Yes. RUCO is recommending that the level of interest on customer deposits be reduced by $354,000. The adjustment reflects a known and measurable change and can be seen in Schedule WAR-4.

Q. How did you determine your recommended level of interest on customer deposits?

A. I multiplied the customer deposit balance, that was booked on December 31 of the Test Year, times an updated one-year constant maturities rate that appeared in the Federal Reserve's website on January 26, 2004. The daily rate, listed for January 2, 2004, is 1.31 percent, or 89 basis points[3] lower than the 2.20 percent January 2, 2003 rate used in the Company's application. The 1.31 percent rate that I used was the published rate for the first business day of 2004. This is the same rate used by APS to calculate interest on customer deposits.

[3] 100 basis points are equal to 1.00 percent.

Operating Adjustment #13 – Property Taxes

Q. Please describe your adjustment to property tax expense.

A. The adjustment to property taxes was calculated by using the methodology used by DOR for determining the amount of property taxes owed. In performing the calculation, the level of Test Year plant in service was reduced by the Test Year amounts of land and transportation assets that were booked in the Company's plant in service account. The reduced amount of plant, less accumulated depreciation, was then increased by the level of materials and supplies on hand at the end of the Test Year and by 50 percent of the construction work in progress that was booked on December 31, 2002. This amount represents the Company's full cash value. Per DOR guidelines, 25 percent of this full cash value (i.e. the assessed value) was subject to the Company's property tax rate of 9.60 percent. This results in a property tax liability of $103,381,000, which is $3,760,000 less than the $107,141,000 level of property tax expense proposed by APS. The property tax calculation, which I have just described, is exhibited in Schedule WAR-5.

Operating Adjustment #14 – Income Taxes

Q. Have you calculated an appropriate level of income tax expense based on RUCO's recommended adjusted operating income for APS?

A. Yes I have. My adjustment for income tax expense is exhibited in Schedule WAR-6.

Q. Does your calculation of income tax expense use the synchronized interest methodology to determine the amount of interest expense to be deducted from income tax?

A. Yes it does. The interest synchronization portion of my income tax liability calculation appears in Note (a) on Schedule WAR-6. The calculation multiplies RUCO witness Marylee Diaz Cortez's recommended level of rate base times RUCO witness Stephen Hill's recommended weighted cost of debt.

Operating Adjustment #15 – Schedule 1 Changes

Q. Please explain your adjustment, which reduces APS' electric operating revenues by $62,629.

A. My $62,629 downward adjustment to APS' electric operating revenues is based on the service charge recommendations of RUCO witness Dr. John Stutz. The RUCO adjusted service charges, which are exhibited in Column (F) of Schedule WAR-7, reflect Dr, Stutz's recommended elimination of the Company's proposed Trip Charge and the maximum amount of increase to all of the remaining charges (with the exception of the TONP @ Poll charge) under his 15.0 percent cap recommendation[4].

Q. Does this conclude your testimony on APS?

A. Yes, it does.

[4] Found in Section 8 of the direct testimony of Dr. John Stutz.

Qualifications of William A. Rigsby

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Revenue Auditor II
Arizona Department of Revenue
Corporate Income Tax Audit Unit
Phoenix, Arizona
November 1993 – October 1994

Tax Examiner Technician I
Arizona Department of Revenue
Transaction Privilege Tax Audit Unit
Phoenix, Arizona
July 1991 – November 1993

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-03-0437
TABLE OF CONTENTS TO SCHEDULES WAR

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 1999
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL (000'S)

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	CASH WORKING CAPITAL PER COMPANY	$	54,098	COMPANY SCH. B-5, PG. 1
2	CASH WORKING CAPITAL PER RUCO		(21,341)	SCH. WAR-1, PG. 2
3	CASH WORKING CAPITAL ADJUSTMENT	$	(75,439)	LINE 2 - LINE 1
4	MATERIALS & SUPPLIES PER COMPANY	$	79,985	COMPANY SCH. B-5, PG. 1
5	MATERIALS & SUPPLIES PER RUCO		79,985	COMPANY SCH. E-1, PG. 1
6	MATERIALS & SUPPLIES ADJUSTMENT	$	-	LINE 5 - LINE 4
7	FUEL - COAL AND OIL PER COMPANY	$	28,185	COMPANY SCH. B-5, PG. 1
8	FUEL - COAL AND OIL PER RUCO		28,185	COMPANY SCH. E-1, PG. 1
9	FUEL - COAL AND OIL ADJUSTMENT	$	-	LINE 7 - LINE 8
10	FUEL - NUCLEAR, NET PER COMPANY	$	7,466	COMPANY SCH. B-5, PG. 1
11	FUEL - NUCLEAR, NET PER RUCO		7,466	COMPANY SCH. E-1, PG. 1
12	FUEL - NUCLEAR, NET ADJUSTMENT	$	-	LINE 10 - LINE 11
13	PREPAYMENTS PER COMPANY	$	5,979	COMPANY SCH. B-5, PG. 1
14	PREPAYMENTS PER RUCO		5,979	COMPANY SCH. B-5, PG. 1
15	PREPAYMENTS ADJUSTMENT	$	-	LINE 11 - LINE 10
16	TOTAL WORKING CAPITAL ADJUSTMENT	$	(75,439)	SUM OF LINES 3, 6, 9, 12 & 15

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CASH WORKING CAPITAL LEAD/LAG CALCULATION

LINE NO.	DESCRIPTION	(A) TOTAL EXPENSES COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED EXPENSES	(D) REVENUE LAG DAYS	(E) EXPENSE LAG DAYS	(F) NET LAG DAYS	(G) CWC FACTOR	(H) WORKING CAPITAL REQUIREMENT
1	FUEL FOR ELECTRIC GENERATION:								
2	COAL	$ 138,717,000	$ 8,683,362	$ 147,400,362	41.81069	30.86168	10.94901	0.03000	$ 4,422,011
3	NATURAL GAS	49,320,000	3,082,105	52,402,105	41.81069	41.62912	0.18157	0.00050	26,201
4	FUEL OIL	1,220,000	68,351	1,288,351	41.81069	27.40279	14.40790	0.03947	50,851
5	NUCLEAR:		-						
6	AMORTIZATION	26,740,000	1,675,421	28,415,421	0.00000	0.00000	0.00000	0.00000	-
7	SPENT FUEL	11,178,000	700,369	11,878,369	41.81069	76.37500	-34.56431	-0.09470	(1,124,882)
8	TOTAL	$ 227,175,000	$ 14,209,608	$ 241,384,608					$ 3,374,182
9	PURCHASED POWER	$ 330,952,000	$ 20,736,125	$ 351,688,125	41.81069	37.83806	3.97263	0.01088	$ 3,826,367
10	TRANSMISSION BY OTHERS	10,743,000	-	10,743,000	41.81069	34.02490	7.78579	0.02133	229,148
11	TOTAL	$ 341,695,000	$ 20,736,125	$ 362,431,125					$ 4,055,515
12	OTHER OPERATIONS & MAINTENANCE:								
13	PAYROLL	$ 218,822,000	$ (11,124,386)	$ 207,697,614	41.81069	18.44744	23.36325	0.06401	$ 13,294,724
14	SEVERANCE	5,068,000	(6,972,384)	(1,904,384)	0.00000	0.00000	0.00000	0.00000	-
15	PENSION AND OPEB	45,964,000	-	45,964,000	0.00000	0.00000	0.00000	0.00000	-
16	EMPLOYEE BENEFITS	17,723,000	-	17,723,000	41.81069	17.02000	24.79069	0.06792	1,203,746
17	PAYROLL TAXES	13,677,000	-	13,677,000	41.81069	13.98000	27.83069	0.07625	1,042,871
18	MATERIALS & SUPPLIES	52,358,000	-	52,358,000	42	29.34000	12.47069	0.03417	1,789,073
19	FRANCHISE PAYMENTS	-	-	-	41.81069	68.19607	-26.38538	-0.07229	-
20	VEHICLE LEASE PAYMENTS	7,228,000	-	7,228,000	41.81069	38.09947	3.71122	0.01017	73,509
21	RENTS	5,649,000	-	5,649,000	41.81069	-31.71012	73.52081	0.20143	1,137,878
22	PALO VERDE LEASE	45,202,000	-	45,202,000	41.81069	53.29167	-11.48098	-0.03145	(1,421,603)
23	PALO VERDE SALE/LOSS GAIN AMORT.	(4,576,000)	-	(4,576,000)	0.00000	0.00000	0.00000	0.00000	-
24	INSURANCE	2,431,000	-	2,431,000	0.00000	0.00000	0.00000	0.00000	-
25	UNCOLLECTIBLE ACCOUNTS	2,680,000	-	2,680,000	0.00000	0.00000	0.00000	0.00000	-
26	OTHER	203,834,000	(16,587,804)	187,246,196	41.81069	37.55000	4.26069	0.01167	2,185,163
27	TOTAL	$ 616,060,000	$ (34,684,573)	$ 581,375,427					$ 19,305,362
28	DEPRECIATION & AMORTIZATION	$ 331,492,000	$ (57,141,000)	$ 274,351,000	0.00000	0.00000	0.00000	0.00000	$ -
29	AMORT. OF ELECTRIC PLANT ACQ. ADJ.	-	-	-	0.00000	0.00000	0.00000	0.00000	-
30	AMORT. OF PROP. LOSSES & REG. STUDY COSTS	-	-	-	0.00000	0.00000	0.00000	0.00000	-
31	TOTAL	$ 331,492,000	$ (57,141,000)	$ 274,351,000					$ -
32	INCOME TAXES:								
33	CURRENT:								
34	FEDERAL & STATE	$ 86,606,000	$ 20,679,400	$ 107,285,400	41.81069	60.05000	-18.23931	-0.04997	$ (5,361,051)
35	DEFERRED	-	-	-	0.00000	0.00000	0.00000	0.00000	-
36	TOTAL	$ 86,606,000	$ 20,679,400	$ 107,285,400					$ (5,361,051)
37	OTHER TAXES:								
38	PROPERTY TAXES	$ 106,189,000	$ (15,016,227)	$ 91,172,773	41.81069	212.81731	-171.00662	-0.46851	$ (42,715,356)
39	SALES TAXES	3,955,000	-	3,955,000	0.00000	0.00000	0.00000	0.00000	-
40	TOTAL	$ 110,144,000	$ (15,016,227)	$ 95,127,773					$ (42,715,356)
41	TOTAL	$ 1,713,172,000	$ (51,216,667)	$ 1,661,955,333					$ (21,341,349)

REFERENCES:
COLUMN (A): COMPANY RESPONSE TO RUCO DATA REQUEST 11.3
COLUMN (B): SUM OF RELEVANT OPERATING ADJUSTMENTS IN RUCO SCHEDULE MDC-5, PAGES 1 AND 2
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY WORKPAPER LLR_WP2 9/400
COLUMN (E): COMPANY WORKPAPER LLR_WP2 9/400
COLUMN (F): COLUMN (D) - COLUMN (E)
COLUMN (G): COLUMN (F) ÷ 365 DAYS
COLUMN (H): COLUMN (C) x COLUMN (G)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME ADJUSTMENT #8 - ANNUALIZE PAYROLL (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE WAR-2

LINE NO.		(A) COMPANY TEST YEAR AS FILED	(B) RUCO TEST YEAR ADJUSTMENTS	(C) RUCO TEST YEAR AS ADJUSTED
1	FUEL FOR ELECTRIC GENERATION:			
2	FUEL HANDLING	$ 2,638	$ 246	$ 2,884
3	OPERATIONS:			
4	PRODUCTION	$ 63,687	$ (990)	$ 62,697
5	TRANSMISSION	8,369	(1,069)	7,300
6	DISTRIBUTION	26,874	(3,345)	23,529
7	CUSTOMER ACCOUNTS	32,162	(2,550)	29,612
8	CUSTOMER SERVICE & INFO	914	361	1,275
9	SALES	17,189	307	17,496
10	ADM. & GENERAL	45,447	1,789	47,236
11	TOTAL OPERATIONS	$ 194,642	$ (5,498)	$ 189,144
12	MAINTENANCE:			
13	PRODUCTION	$ 40,861	2,168	$ 43,029
14	TRANSMISSION	2,351	56	2,407
15	DISTRIBUTION	14,393	2,395	16,788
16	ADM. & GENERAL	4,402	1,571	5,973
17	TOTAL MAINTENANCE	$ 62,007	$ 6,190	$ 68,197
18	TOTAL OPERATIONS & MAINTENANCE	$ 259,287	$ 938	$ 260,225
19	PAYROLL ANNUALIZATION ADJUSTMENT PER COMPANY			$ 1,031
20	PAYROLL ANNUALIZATION ADJUSTMENT PER RUCO			$ 938
21	RUCO ADJUSTMENT (LINE 20 - LINE 19)			$ (93)

REFERENCES:
COLUMN (A): COMPANY WORKPAPERS DGR_WP15 3/67 THRU 4/67
COLUMN (B): RUCO WORKPAPER WAR-2
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME ADJUSTMENT #9 - EMPLOYEE SEVERANCE

DOCKET NO. E-01345A-03-0437
SCHEDULE WAR-3

LINE NO.	DESCRIPTION	(A) PER COMPANY WORKPAPER TOTAL	(B) PER COMPANY WORKPAPER APS	(C) PER COMPANY WORKPAPER M&T	(D) PER COMPANY WORKPAPER PIN WEST	(E) PER RUCO AUDIT TOTAL	(F) PER RUCO AUDIT APS	(G) PER RUCO AUDIT M&T	(H) PER RUCO AUDIT PIN WEST	(I) DIFFERENCE
1	TOTAL:									
2	2002 SEVERENCE	$ (35,691,394)	$ (28,220,834)	$ (259,311)	$ (7,211,249)	$ (35,691,394)	$ (28,220,834)	$ (259,311)	$ (7,211,249)	$ -
3	NON-APS POWER PLANT PARTICIPANT SHARE	(3,233,633)	(3,233,633)	-	-	(3,233,633)	(3,233,633)	-	-	-
4	DIFFERENCE - TOTAL (LINE 2 - LINE 3)	$ (32,457,761)	$ (24,987,201)	$ (259,311)	$ (7,211,249)	$ (32,457,761)	$ (24,987,201)	$ (259,311)	$ (7,211,249)	$ -
5	% TO APS O&M:		100.00%	32.88% (a)	66.69% (b)		100.00%	32.88%	66.69%	
6	APS SHARE:									
7	2002 SEVERENCE (LINE 2 X LINE 5)	$ (33,115,277)	$ (28,220,834)	$ (85,261)	$ (4,809,182)	$ (33,115,277)	$ (28,220,834)	$ (85,261)	$ (4,809,182)	$ -
8	NON-APS POWER PLANT PARTICIPANT SHARE (LINE 3 X LINE 5)	(3,233,633)	(3,233,633)	-	-	(3,233,633)	(3,233,633)	-	-	-
9	DIFFERENCE - APS SHARE (LINE 7 - LINE 8)	$ (29,881,644)	$ (24,987,201)	$ (85,261)	$ (4,809,182)	$ (29,881,644)	$ (24,987,201)	$ (85,261)	$ (4,809,182)	$ -
10	COMPANY AVERAGE (LINE 9 ÷ 3 YEARS):	$ (9,960,548)		RUCO AVERAGE (LINE 9 ÷ 10 YEARS):		$ (2,988,164)				$ 6,972,384
11	PRO FORMA (LINE 7 - LINE 10)	$ (23,154,729)				$ (30,127,113)				
12	RUCO ADJUSTMENT									$ (6,972,384)

REFERENCES:
COLUMNS (A) THRU (D): COMPANY WORKPAPER DGR - WP6 2/4
COLUMNS (E) THRU (H): COMPANY WORKPAPER DGR - WP6 2/4
COLUMN (I): COLUMN (E) - COLUMN (A)

NOTES
(a) PER WORKPAPER DGR-WP15 9/67:
$3,052,143 ADJUSTED O&M PAYROLL ÷ $9,281,646 NET PAYROLL = 32.88%

(b) PER WORKPAPERS DGR-WP16 3/4 AND 4/4:
[($3,182,263 PNW COMMON + $3,079,537 SHARED SERVICES COMMON) ÷ $7,211,249 PNW CONSOLIDATED NET PAYROLL] X [30.7% APS GENERAL OPERATIONS COMMON + 46.1% APS COMMERCIAL OPERATIONS COMMON] =
[$6,261,800 ÷ $7,211,249 PNW CONSOLIDATED NET PAYROLL] X [76.8%] = [86.83%] X [76.8%] = 66.69%

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME ADJUSTMENT #12 - INTEREST ON CUSTOMER DEPOSITS (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE WAR-4

LINE NO.	DESCRIPTION	(A) PER COMPANY WORKPAPER	(B) PER RUCO AUDIT	(C) DIFFERENCE
1	CUSTOMER DEPOSIT BALANCE (DECEMBER 31, 2002)	$ 39,795	$ 39,795	$ -
2	TIMES: CONSTANT MATURITY RATE ON 1-YEAR U.S. TREASURY SECURITY	2.20% (a)	1.31%	-0.93%
3	TOTAL INTEREST EXPENSE ON CUSTOMER DEPOSITS	$ 875	$ 521	
4	RUCO ADJUSTMENT			$ (354)

REFERENCES:
COLUMN (A): COMPANY WORKPAPER DGR_WP21 2/3
COLUMN (B): LINE 1 - COMPANY WORKPAPER DGR_WP21 2/3
COLUMN (B): LINE 2 - FEDERAL RESERVE WEBSITE – ONE-YEAR CONSTANT MATURITIES RATE ON JANUARY 2, 2004
COLUMN (C): COLUMN (B) - COLUMN (A)

NOTES
(a) PER WORKPAPER DGR_WP21 3/3:
ONE-YEAR TREASURY CONSTANT MATURITIES RATE EFFECTIVE THE FIRST BUSINESS DAY OF EACH YEAR AS PUBLISHED ON THE FEDERAL RESERVE WEBSITE

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME ADJUSTMENT #13 - PROPERTY TAXES (000's)

DOCKET NO. E-01345A-03-0437
SCHEDULE WAR-5

LINE NO.	DESCRIPTION	AMOUNT		REFERENCE
1	PLANT IN SERVICE	$ 7,105,595	(a)	DIRECT TESTIMONY ROCKENBERGER
2	ACCUMULATED DEPRECIATION	(3,042,592)		SCHEDULE MDC-2
3	NET PLANT	$ 4,063,003		LINE 1 + LINE 2
4	CWIP @ 50%	164,545		COMPANY SCHEDULE E-1
5	MATERIALS & SUPPLIES	79,985		COMPANY SCHEDULE E-1
6	FULL CASH VALUE	$ 4,307,532		SUM LINES 1 THROUGH 5
7	ASSESSED VALUE	$ 1,076,883		LINE 6 x 25%
8	TAX RATE	9.60%		DGR-WP29, PG. 3
9	PROPERTY TAXES	$ 103,381		LINE 7 x LINE 8
10	PROPERTY TAX PER COMPANY	107,141		DGR-WP29, PG. 3
11	ADJUSTMENT	$ (3,760)		LINE 27 - LINE 29

NOTES
(a) PER INFORMATION CONTAINED IN ATTACHMENT LLR - 4:
PLANT IN SERVICE NET OF LAND AND TRANSPORTATION VEHICLES

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME ADJUSTMENT #14 - INCOME TAXES (000'S)

DOCKET NO. E-01345A-03-0437
SCHEDULE WAR-6

LINE NO.	DESCRIPTION	TOTAL AMOUNT	JURISDICTIONAL AMOUNT	REFERENCE
	FEDERAL INCOME TAXES:			
1	OPERATING INCOME BEFORE INCOME TAXES	$ 367,401	$ 365,720	SCH. MDC-4
	LESS:			
2	ARIZONA STATE TAX	18,912	18,814	LINE 11
3	INTEREST EXPENSE	95,993	95,722	NOTE (a)
4	FEDERAL TAXABLE INCOME	252,496	251,185	LINE 1 - LINES 2 & 3
5	FEDERAL INCOME TAX RATE	35.00%	35.00%	TAX RATE
6	FEDERAL INCOME TAX EXPENSE	88,374	87,915	LINE 4 X LINE 5
	STATE INCOME TAXES:			
7	OPERATING INCOME BEFORE INCOME TAXES	367,401	365,720	LINE 1
	LESS:			
8	INTEREST EXPENSE	95,993	95,722	NOTE (a)
9	STATE TAXABLE INCOME	271,408	269,999	LINE 7 - LINE 8
10	STATE TAX RATE	6.968%	6.968%	TAX RATE
11	STATE INCOME TAX EXPENSE	18,912	18,814	LINE 9 X LINE 10
12	TOTAL INCOME TAXES	107,285	106,728	LINE 6 + LINE 11
13	INCOME TAXES PER COMPANY	86,606	86,144	COMPANY SCH. C-1, PG. 2
14	ADJUSTMENT	$ 20,679	$ 20,584	LINE 12 - LINE 13

NOTE (a)
INTEREST SYCHRONIZATION

	TOTAL AMOUNT	JURISDICTIONAL AMOUNT
ADJUSTED RATE BASE	$ 3,060,147	$ 3,051,479
WEIGHTED COST OF DEBT	3.14%	3.14%
INTEREST EXPENSE	$ 95,993	$ 95,722

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2002
OPERATING INCOME ADJUSTMENT #15 - SCHEDULE 1 CHANGES

DOCKET NO. E-01345A-03-0437
SCHEDULE WAR-7

LINE NO.	CHARGE	(A) CURRENT CHARGES PER COMPANY	(B) PROPOSED CHARGES PER COMPANY	(C) YE 2002 VOLUME PER COMPANY	(D) IMPACT PER COMPANY	(E) CURRENT CHARGES PER RUCO	(F) PROPOSED CHARGES PER RUCO (a)	(G) YE 2002 VOLUME PER RUCO	(H) IMPACT PER RUCO	(I) DIFFERENCE CURRENT CHARGES	(J) DIFFERENCE PROPOSED CHARGES	(K) DIFFERENCE YE 2002 VOLUME	(L) DIFFERENCE IMPACT
1	TRIP CHARGE	$ -	$ 17.50	1,050	$ 18,375.00	$ -	$ -	1,050	$ -	$ -	$ (17.50)	$ -	$ (18,375.00)
2	AFTER HOURS CHARGE - REGULAR	$ 50.00	$ 75.00	1,198	$ 29,950.00	$ 50.00	$ 57.50	1,198	$ 8,985.00	$ -	$ (17.50)	$ -	$ (20,965.00)
2	AFTER HOURS CHARGE - SPECIAL	$ -	$ 150.00	65	$ 9,750.00	$ 50.00	$ 57.50	65	$ 487.50	$ 50.00	$ (92.50)	$ -	$ (9,262.50)
3	TONP @ POLE	$ 87.50	$ 100.00	336	$ 4,200.00	$ 87.50	$ 100.00	336	$ 4,200.00	$ -	$ -	$ -	$ -
4	ON-SITE ENERGY EVALUATIONS	$ 50.00	$ 90.00	297	$ 11,880.00	$ 50.00	$ 57.50	297	$ 2,227.50	$ -	$ (32.50)	$ -	$ (9,652.50)
5	JOINT SITE MEETINGS	$ 30.00	$ 70.00	-	$ -	$ 30.00	$ 34.50	-	$ -	$ -	$ (35.50)	$ -	$ -
6	METER RE-READS	$ 10.00	$ 20.00	268	$ 2,680.00	$ 10.00	$ 11.50	268	$ 402.00	$ -	$ (8.50)	$ -	$ (2,278.00)
7	METER TEST - SHOP	$ 25.00	$ 30.00	81	$ 405.00	$ 25.00	$ 28.75	81	$ 303.75	$ -	$ (1.25)	$ -	$ (101.25)
8	METER TEST - FIELD	$ 25.00	$ 100.00	28	$ 2,100.00	$ 25.00	$ 28.75	28	$ 105.00	$ -	$ (71.25)	$ -	$ (1,995.00)
9	TOTALS (SUM OF LINES 1 THRU 8)				$ 79,340.00				$ 16,710.75				
10	RUCO ADJUSTMENT (SUM OF LINES 1 THRU 8)												$ (62,629.25)

REFERENCES:
COLUMN (A): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (B): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (C): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (D): COMPANY WORKPAPER DGR_WP10 2/2 [COLUMN (B) - COLUMN (A)] x COLUMN (C)
COLUMN (E): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (F): TESTIMONY - DR. JOHN STUTZ
COLUMN (G): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (H): [COLUMN (F) - COLUMN (E)] x COLUMN (G)
COLUMN (I): COLUMN (E) - COLUMN (A)
COLUMN (J): COLUMN (F) - COLUMN (B)
COLUMN (K): COLUMN (G) - COLUMN (C)
COLUMN (L): COLUMN (H) - COLUMN (D)

NOTE
(a) THE PROPOSED CHARGES PER RUCO, EXHIBITED IN COLUMN (F), REFLECT THE FULL EFFECT OF AN INCREASE IN CHARGES UNDER THE 15.0% CAP RECOMMENDATION MADE BY RUCO WITNESS DR. JOHN STUTZ.

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	)	Docket No. E-01345A-03-0437

DIRECT TESTIMONY

OF

DR. RICHARD A. ROSEN

On Behalf of the Arizona Residential Utility Consumer Office

Tellus Institute
11 Arlington Street
Boston, MA 02116-3411
Tel: 617/266-5400

February 3, 2004

TABLE OF CONTENTS

I. SUMMARY AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, a M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president and secretary/treasurer of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resources, and environmental research. Within Tellus Institute, the Electricity Program focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. As past director of the Energy Group and manager of the Electricity Program, I have had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. I have also reviewed the prudence of many past supply-planning decisions by utilities.

Q. PLEASE PROVIDE A FEW ADDITIONAL DETAILS OF YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past 24 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna Unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission ("FERC") on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec. In the 1980s, I testified in several cases involving the planning and construction of the Palo Verde nuclear units, before the Arizona Corporation Commission ("Commission" or ACC), as well as before FERC.

Finally, in January 1998, I testified before this Commission on behalf of the Residential Utility Consumer Office ("RUCO") in Docket No. U-0000-94-165 regarding public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; and presentation of the "retail generation service" methodology for computing stranded costs. In September 1998, in Docket No. E-01933A-98-0471, I was the author of comments to the Commission entitled "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." In November 1998, I filed testimony before the Commission in Docket Nos. E-

01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473; E-01345A-97-0773; and U-00000C-94-165 on various filings related to the unbundled service tariffs, stranded cost recovery proposal for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals. I filed testimony before the Commission in Docket No. RE-00000C-94-0165 in July 1999 on the status of settlement discussions between RUCO and Citizens Utilities Company-Arizona Electric Division ("CUC-AED"), and summary concerns about CUC-AED's stranded cost recovery plans. In February 2002, I filed testimony before the Commission in Docket No. E-01032C-00-0751 on Citizens Communications Company's Purchased Power and Fuel Adjustment Clause and its wholesale power supply contract with Arizona Public Service. I also testified before the ACC regarding Track A and Track B issues in docket E-00000A-02-0051 et al.

Due to my extensive regulatory experience supporting the public interest, as outlined above, in 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the U.S. Department of Justice, the National Association of Regulatory Utility Commissioners (NARUC), the New England Conference of Public Utility Commissioners, the New England

Governors Conference, and the National Council on Competition in the Electric Industry.

In the last seven years, I have spent most of my time analyzing electric utility restructuring issues. As early as 1996, I testified before the New Hampshire Public Utilities Commission on issues affecting the design of the state's pilot programs (Docket No. 96-150), and I testified before the New York Public Service Commission on stranded costs, market structures, and other issues related to ConEd's, NYSEG's, and RG&E's restructuring plans. I also have worked on or testified on other restructuring issues in Nevada, New Mexico, New Jersey, Illinois, Missouri, Colorado, Pennsylvania, Maryland, Maine, Rhode Island, Utah and Michigan. Finally, I have recently authored a series of comments to FERC on Regional Transmission Organizations and Standard Market Design for several state attorneys general and consumer advocates. Exhibit___(RAR-1) provides a copy of my resume.

Q. PLEASE SUMMARIZE THE ISSUES ON WHICH YOU WILL TESTIFY.

A. My testimony covers two different sets of issues that affect APS' request for a change in its base rates for Standard Offer Service. The first set of issues deals with how APS should charge its retail customers for the cost of transmission service used to transmit power to retail loads. The second set of issues deals with how APS should charge its retail customers for fuel and purchased power costs, how APS should credit its retail customers for net income earned on wholesale sales, and how the risk of mis-estimates of those future costs in this ratecase should be shared between APS retail ratepayers and stockholders.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THESE TWO MAJOR ISSUE AREAS.

A. With respect to the first issue, I recommend that for several reasons it would be best for APS retail customers if the Arizona Corporation Commission retained jurisdiction over as much of the transmission service required by these customers as it can. The ACC jurisdictional transmission service contrasts with that portion of transmission service provided by APS for the wholesale transmission of power, over which FERC has jurisdiction. I believe that the ACC can and should retain jurisdiction over that portion of transmission service provided by APS to transmit power produced by any power plant that it owns to its own retail customers on a bundled basis. This goal can be achieved if the ACC eliminates the possibility of retail competition after July 1, 2004 for any of APS' retail customers, so that FERC can no longer claim that APS' retail rates are unbundled rates. All other uses of the APS transmission system would need to be charged to either retail or wholesale customers using the FERC approved OATT (Open Access Transmission Tariff) rate, since these uses would involve wholesale transactions.

Pursuant to this recommendation, the appropriate revenue requirement for transmission service for APS retail customers should be computed based on the sharing of regulatory jurisdiction as described above. Doing so will cause the revenue requirements for transmission service to be properly allocated between the ACC jurisdictional and FERC jurisdictional customers.

I also recommend that Mr. Propper's proposal to establish a Transmission Cost Adjustment Clause be rejected, since it does not meet the ACC's own standards justifying an adjustment clause.

With respect to the <u>second</u> main issue, in Decision No. 66567, the Commission has requested comments in this rate case as to how the impact of any mis-estimates in APS' forecasts of the costs of purchased power in the future, relative to the baseline levels approved in this ratecase, should be allocated between retail ratepayers and APS stockholders. I have concluded that most of APS' purchased power costs in the next few years would not be very volatile because they would be incurred primarily under fixed cost contracts. As a consequence, there is no need for APS to adopt a purchased power adjustment clause. Furthermore, any volatility in off-system sales revenues will tend to off-set volatility in purchased power costs, such that <u>net</u> purchased power costs will have a small impact on overall cost volatility.

Thus, my recommendation regarding the second main issue is that the retail ratepayers should only pay for the costs of fuel and purchased power as estimated by APS for their base rates as approved by the ACC in this ratecase. In addition, only the retail ratepayers should be credited with any net wholesale sales income earned on power sales from generating units included in the APS ratebase. If APS finds that it is significantly under-collecting its fuel and purchased power costs incurred for serving retail customers in the future, it can apply for a change in its base rates.

As partial justification for my recommendation that a purchased power adjustment clause is not needed, I completely support the arguments made by Ms. Marylee Diaz Cortez of RUCO in her direct and surrebuttal testimony in ACC Docket No. E-01345A-02-0403 as to why the ACC should not adopt any type of purchased power adjustment clause. Specifically, I agree that approval of APS' proposal for a PSA would require the ACC to reverse its 1989 Decision No. 56450 with respect to these matters. In addition, Ms. Cortez also showed that an up-do-date review of APS' fuel costs per kWh showed fairly modest changes for 2000-2002. Thus, these fuel costs were not sufficiently volatile to justify their inclusion in a fuel adjustment clause, or in a fuel and purchased power adjustment clause.

II. TRANSMISSION SERVICE JURISDICTION AND RETAIL REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE THE CURRENT SITUATION, AS YOU UNDERSTAND IT, AS TO WHICH REGULATORY AUTHORITIES HAVE JURISDICTION OVER THE TRANSMISSION SERVICE PROVIDED BY APS' TRANSMISSION ASSETS.

A. As I understand the current situation, FERC Order No. 888 made it clear that FERC claims authority over transmission service terms and conditions whenever any vertically integrated electric utility like APS has transmission assets that are either being used to serve wholesale customers directly, or are being used to supply power from third-party (or PWEC) generating units to APS' retail customers. (See 18 CFR 35-28(c)(2).) In addition, in the context of Order No. 888, "wholesale customers" include retail customers once a state has decided to <u>unbundle</u> its retail service due to the onset of retail competition for retail customers. Finally, the US Supreme Court in *New York v. FERC* (decided on March 4, 2002) confirmed that FERC can assert authority over the terms and conditions of all transmission service provided to a utility's retail customers, *if* the state has decided to allow retail competition for those customers, thus unbundling their retail electric rates. (Case No. 00-568)

Q. DO YOU KNOW IF THE ARIZONA CORPORATION COMMISSION HAS PREVIOUSLY TAKEN A POSITION AS TO WHETHER OR NOT IT

FAVORS TRYING TO MAXIMIZE ITS AUTHORITY OVER APS' TRANSMISSION ASSETS IN THE FUTURE?

A. Yes, during the course of FERC Docket No. ER00-3583-001, the ACC expressed the view that the Standard Offer Service that APS was providing to its retail customers was a *bundled* retail service, and, therefore, FERC did not have jurisdiction over the price and terms of the transmission service included as part of its Standard Offer Service. Thus, the ACC appeared to be resisting the extension of FERC authority to include the transmission component of Standard Offer Service prior to the Supreme Court's decision in *New York v. FERC*.

However, in FERC's "Order Denying Rehearing..." of March 16, 2001 in that docket, FERC disagreed with the ACC and declared that Standard Offer Service in Arizona was an unbundled service. This implied, in FERC's view, that Standard Offer Service, such as that provided by APS to its customers, "becomes separate [wholesale] transmission and power sales transactions, [whereby] the resulting transmission transaction falls within the Federal sphere of regulation." (Order, p. 5) As FERC repeated, "once the state commission adopts a system where generation service is available as a separate product, the transmission service is within this Commission's exclusive jurisdiction under the Federal Power Act." (Order, p. 5)

Q. WHAT ARE THE ADVANTAGES OF THE ARIZONA CORPORATION COMMISSION MAINTAINING THE MAXIMUM DEGREE OF AUTHORITY OVER TRANSMISSION SERVICE FOR RETAIL CUSTOMERS IN ARIZONA?

A. In my opinion, there are several existing as well as potential advantages for Arizona retail consumers to have the ACC maintain the maximum level of regulatory authority possible over the transmission assets in Arizona used to serve the retail customers of Arizona's vertically integrated electric utilities. The <u>first</u> advantage is that the ACC is more likely than FERC to carefully attend to whether or not the price of the transmission component of electric rates is as just and reasonable for electric retail customers as conditions change. <u>Secondly,</u> maximizing its authority over transmission will help the ACC to be able to assure retail customers (native load) that they get first priority in the use of APS' transmission assets to serve their needs, both from a system reliability and economic standpoint. This is justified since the relevant transmission lines were built to primarily serve native load, and since the lines have been paid for primarily through retail rates. For example, the ACC would be able to set rules as to the Firm Transmission Rights (FTRs) that Arizona utilities will have available for the purpose of using their own transmission assets to serve retail loads, including sufficient FTRs to provide transmission capacity reserves in order to maintain adequate levels of system reliability.

<u>Thirdly,</u> if the ACC maintains a maximum level of jurisdiction over the retail use of transmission assets within Arizona, this will very likely help to provide continued legal protection to prevent Arizona electric utilities from having to join a Regional Transmission Organization (RTO), which is a problematic creation of FERC's. It may very well be in the interest of Arizona's electric ratepayers not to have Arizona utilities join an RTO, because of the many

negative characteristics of such an organization, especially the Standard Market Design that FERC has so far insisted on for all RTOs. In my opinion, the ACC should do everything in its power to keep Arizona's electric utilities from being forced to participate in an RTO (as opposed to a cost-based regional power pool), especially if it includes FERC's proposed Standard Market Design. In this regard, over the last two years, I have drafted many sets of comments to FERC on this and related issues that have been signed by the consumer advocates and/or attorneys general of New Mexico, Utah, Colorado, and Rhode Island, as well as by other consumer protection organizations.

Fourthly, I believe that if the ACC retains jurisdiction over the bundled retail component of transmission service in Arizona, thus helping to avoid RTO membership for Arizona's electric utilities, this will also prevent the adoption by FERC of the additional returns on equity for these transmission assets (so-called "financial incentives") that FERC has proposed allowing for utilities that do join RTOs. Not having to pay for those unneeded financial incentives, as proposed by FERC, will directly save retail ratepayers money.

Q. BECAUSE OF THE POTENTIAL BENEFITS OF MAINTAINING ACC JURISDICTION OVER THE RETAIL USE OF THE TRANSMISSION ASSETS OF ARIZONA's ELECTRIC UTILITIES, WHAT DO YOU RECOMMEND THAT THE ACC DO TO PREVENT FERC FROM HAVING COMPLETE REGULATORY CONTROL OVER THOSE ASSETS?

A. In light of the current legal situation affecting the transmission assets of vertically integrated electric utilities, I recommend to the ACC that they repeal the

Commission's competition rules that established retail competition for retail customers in Arizona. I believe that if the ACC repeals these rules prior to July 1, 2004, then FERC Order No. 888 and the resulting Open Access Transmission Tariff (OATT) that resulted from this order, will no long apply to Arizona's electric utilities with respect to the bundled retail use of their transmission assets for the purpose of transmitting power from their own power plants to retail customers. If this is done prior to July 1, 2004, then APS' Standard Offer Service will cease to exist as an <u>unbundled</u> service, and traditional <u>bundled</u> retail service will again be the only type of electric service offered to retail customers. The ACC will, then, be free to set the revenue requirements for the bundled retail component of transmission service as it sees fit as part of this ratecase.

Q. IN ITS RATECASE FILING DID APS TAKE A POSITION ON THE JURISDICTIONAL ISSUES DISCUSSED ABOVE?

A. Yes, Mr. Robinson stated on page 15 of his direct testimony that FERC rules required APS to use the FERC OATT rates for pricing <u>all</u> components of Standard Offer transmission service. Because of this, Mr. Robinson removed *all* of the assets and costs associated with APS' transmission system from his revenue requirements calculations in this ratecase, as a pro forma adjustment. In their place, Mr. Robinson charged all APS' retail customers for all the transmission service provided to them using the OATT rates. In addition, Mr. Robinson's response to RUCO data request 13.1 pointed to FERC's decision in Docket No. ER00-3583-000, et al. as justification for APS' position on transmission pricing.

Q. IF THE ACC AGREES WITH YOUR RECOMMENDATION THAT IT RETAIN JURISDICTION OVER THE RETAIL USE OF APS' TRANSMISSION ASSETS BY ENDING RETAIL COMPETITION IN ARIZONA, OR AT LEAST FOR APS, HOW SHOULD APS CALCULATE THE REVENUE REQUIREMENTS FOR RETAIL TRANSMISSION SERVICE IN THIS RATECASE?

A. If the ACC retains authority over the bundled retail use of APS' transmission system assets, then APS should calculate the revenue requirements of this ACC jurisdictional service in two steps. The <u>first</u> step is to allocate the appropriate amount of transmission system asset costs (both fixed costs and expenses) to ACC jurisdictional customers, on a monthly basis for the test year, corresponding to the retail use of the transmission system for the purpose of transmitting power from generating units owned by APS (including the PWEC units if purchased by APS) to APS' retail customers. In other words, the appropriate numerical values for the use of the transmission system (in megawatts) to serve the coincident monthly peak retail demand, and monthly energy flows (in MWH) to serve retail customers directly from APS' owned generating units, should be used to determine what fraction of the fixed and variable costs, respectively, associated with the entire APS transmission system should remain in the ACC jurisdictional revenue requirement analysis directly.

The <u>second</u> step necessary to compute the total revenue requirements for APS' use of its transmission system for the purpose of serving bundled retail load is to use the OATT rates to determine the cost of serving the remainder of the

APS retail load on a month-to-month basis that is not supplied directly from APS' owned generating units. The revenue requirement results for each of these two steps should, then, be added together to obtain the total revenue requirements for transmission service for APS' retail customers.

Q. WHAT IS THE REGULATORY BASIS FOR THE FIRST STEP IN THE CALCULATION OF RETAIL REVENUE REQUIREMENTS THAT YOU HAVE OUTLINED ABOVE?

A. Again, the first step represents the bundled retail use of transmission service to transmit power from APS' owned generating units directly to retail customers. This component of transmission service would be part of the new bundled retail service provided by APS to all of its retail customers, and it would be completely under the jurisdiction of the state public utility commission. If retail competition is ended by July 1, 2004, then, there is no aspect of this type of use of the transmission system that represents a wholesale transaction, and, therefore, it would not be under FERC's jurisdiction.

Q. WHAT IS THE REGULATORY BASIS FOR THE SECOND STEP IN YOUR CALCULATION OF TRANSMISSION REVENUE REQUIREMENT FOR RETAIL CUSTOMERS?

A. In contrast, the use of APS' transmission system as described in step #2 above to supply additional amounts of power to retail customers from wholesale purchases, whether from PWEC plants, or from third-party plants, would represent a wholesale transaction. Thus, these two types of wholesale uses of the APS transmission system would be under FERC's jurisdiction according to both FERC

Order No. 888 and the Federal Power Act. That is why the results of the second step in the calculation of transmission revenue requirements for retail customers using the FERC OATT tariff rates must be included when calculating the total cost of transmission service for retail customers.

In addition, there is a third type of use of the APS transmission system that does <u>not</u> contribute to retail revenue requirements. APS' transmission system will also provide for the delivery of wholesale purchases of power to APS' <u>wholesale customers</u> (such as coop and wheeling-through customers), and these wholesale customers should also pay their fair portion of the total wholesale and retail revenue requirements for all transmission service under the FERC OATT rates. In summary, then, the three components of APS' total transmission revenue requirements are for:

1. <u>retail</u> service directly from APS' plants (ACC jurisdictional);
2. <u>retail</u> service from APS' wholesale contracts for purchases and sales of power (FERC jurisdictional);
3. service to <u>wholesale</u> customers from other wholesale contracts, or for wheeling through the APS system (FERC jurisdictional).

Q. DID YOU REQUEST THAT APS MAKE A CALCULATION OF THE ACC JURISDICTIONAL (RETAIL) TRANSMISSION SERVICE REVENUE REQUIREMENTS USING THE METHODOLOGY THAT YOU DESCRIBED ABOVE IN YOUR FIRST STEP?

A. Yes, in RUCO data request 15.1, I requested that APS make the revenue requirement calculation as described above in the first and second steps in the form of a change to the retail revenue requirements that they were claiming in this case in Mr. Robinson's direct testimony which was based on 100 percent use of the OATT wholesale tariff rate for this purpose. Unfortunately, Mr. Propper's response was not helpful in terms of computing the relevant revenue requirement, since it appears that he did not understand the requested calculation. (See answer to RUCO 15.1.)

Q. ON PAGE 18 OF MR. PROPPER'S TESTIMONY HE PROPOSES THE ADOPTION OF A TRANSMISSON COST ADJUSTMENT CLAUSE. DO YOU AGREE WITH MR. PROPPER'S PROPOSAL FOR SUCH A CLAUSE?

A. No, I do not believe there is any reason for the ACC to adopt a Transmission Cost Adjustment Clause for APS retail customers. As discussed below, the main criteria that the ACC has previously accepted for justifying the adoption of adjustment clauses is that the relevant costs are significant and volatile. Yet, Mr. Propper provides no evidence at all in his testimony in this case that the retail component of transmission service costs meets these Commission criteria. He does not show that there is likely to be any significant degree of volatility in those costs, on a cents-per-kWh basis. In fact, it is very unlikely that actual transmissions costs per kWh would vary significantly from the baseline costs per kWh as set in the ratecase, since transmission costs are less than 10 percent of revenue requirements, and because they will tend to be proportional to sales. Thus, the adoption of a Transmission Cost Adjustment Clause has not been sufficiently justified in Mr. Propper's testimony, and I recommend that the request for such a clause be denied.

III. THE PURCHASED POWER ADJUSTMENT CLAUSE

Q. PLEASE SUMMARIZE THE CURRENT STATUS OF RETAIL COMPETITION IN ARIZONA AND DESCRIBE THE IMPACT OF THIS SITUATION ON THE NEED FOR A PURCHASED POWER ADJUSTMENT CLAUSE.

A. Currently, retail competition does not functionally exist in Arizona. My understanding is that no significant number of APS' retail customers have ever chosen to purchase their electric generation supplies directly from a third- party provider, and none are doing so presently. Furthermore, it is my understanding that for many reasons RUCO will be recommending to the ACC that the Electric Competition Rules be modified in a manner to end retail competition in Arizona as an option for the retail customers of APS prior to July 1, 2004. In addition, I have just made the same recommendation above, in order that the ACC can retain jurisdiction over as much of the APS transmission system as possible.

It is especially true that if retail competition is ended in Arizona prior to July 1, 2004, then Ms. Diaz Cortez's testimony on behalf of RUCO in Docket No. E-01345A-02-0403 will retain all of its original relevance and force as to why a purchased power adjustment clause for APS should not be implemented. As Ms. Diaz Cortez pointed out, that aspect of the original settlement agreement of 1999 to consider establishing a purchased power adjustment clause would no longer have much relevance if retail competition proved to be ineffective, or was ended. This is because such a clause was presumed useful only when APS was purchasing 100 percent (or a very high fraction) of its power supplies on a wholesale basis, and was not providing any significant fraction of the power demanded by its retail customers from its own power plants. In that situation, purchased power costs would completely dominate fuel costs. However, since it is clear now that APS will still generate much of the power supply needs of its retail customers from generating units that it owns for the foreseeable future, an adjustment clause for purchased power alone is far less necessary than was originally thought to be the case.

In addition, in the interim, the Track B power procurement process has been concluded. This means that the additional power requirements of APS that can not be generated from its own power plants will be purchased under contract pricing arrangements that will not be subject to as high a degree of price volatility as spot market purchased power might be. Furthermore, it would seem that only a very small fraction of the net power supply needs of APS customers could be prudently served from spot market power purchases anyway. Accordingly, only a very small fraction of APS' purchased power costs might be volatile. If, then, APS' off-system <u>sales</u> of power that will occur at market prices are netted against its projected power <u>purchases</u> at market prices, changes in the cost of the one will tend to off-set changes in the cost of the other. Thus, the ACC only needs to focus on the potential price volatility of these <u>net</u> power purchases, since market price fluctuations will tend to affect both sales and purchases similarly.

I relied on the APS forecasts for wholesale purchases and sales used for setting their proposed base rates in this ratecase to perform such a calculation. Mr.

Robinson's Workpaper number DGR-WP13, page 2, indicates that only about $10 million in *net* power purchases, out of about $584 million in total fuel and purchased power costs for 2003, can be expected. This calculation implies that the cost of net power purchases is likely to be so small that even if this cost were volatile a purchased power adjustment clause would not be justified. (Note that this workpaper assumes that the PWEC generating units are not included in the APS ratebase.) In addition, when considering whether or not a purchased power adjustment clause is needed, another important factor to consider is how the average net cost of purchased power changes on a <u>multi-year</u> <u>average</u> basis between ratecases, and not just how much volatility exists in this quantity from <u>year to year</u>. This is important because one year's increase in actual purchased power costs relative to base rate costs can be off-set by another year's decrease in such costs relative to base rates.

In light of all these considerations, it will not be necessary for the ACC to implement a purchased power adjustment clause for APS in order to reduce the average degree of risk faced by APS stockholders to reasonable levels between ratecases. Furthermore, not implementing a purchased power adjustment clause will provide APS management with a very strong incentive to minimize both its purchase power and fuel costs jointly. Finally, denying the PSA will not create the problems associated with piecemeal regulation that the ACC itself cited in Decision No. 56450.

Q. IN THE ACC'S RECENT DECISION NO. 66567 REGARDING APS' PROPOSAL FOR VARIOUS ADJUSTMENT MECHANISMS, THE ACC

STATED THAT THE PROPER TREATMENT OF ANY WHOLESALE MARKET CREDITS EARNED BY APS SHOULD BE DEALT WITH AS PART OF THE CURRENT RATECASE (P. 16). HOW WOULD YOUR PROPOSAL NOT TO IMPLEMENT ANY PURCHASED POWER ADJUSTMENT MECHANISM FOR APS BEGINNING IN JULY 2004 AFFECT THIS ISSUE?

A. If the ACC adopts my proposal to have no purchased power adjustment mechanism for APS' retail rates, then the ACC should also simply require APS to flow <u>all</u> projected net income from wholesale sales made from APS' owned generating units or purchased power contracts to the <u>retail</u> ratepayers, with no portion of this net income going to <u>wholesale</u> customers. This net income from wholesale sales should be forecast by APS on a consistent basis with its forecasts of all other fuel and purchased power costs, as they claim to have done in the ratecase filing. However, if the actual future net income from wholesale sales differs from the forecast amount on a test year basis, then just as for fuel and purchased power costs forecast to serve retail load, any differences in net income from wholesale sales relative to the baseline forecast would not be recovered from (or charged to) retail customers.

Q. HOW DID APS TREAT NET INCOME FROM WHOLESALE SALES IN ITS FORECASTS OF ITS NET COSTS OF PURCHASED POWER WHEN CALCULATING RETAIL REVENUE REQUIREMENTS IN THIS RATECASE FILING?

A. According to Mr. Robinson's Attachment DGR-5, page 8, it appears as if he credited the <u>total</u> Company revenue requirements with "normalized off-system revenue – 2003," as opposed to just crediting the ACC jurisdictional revenue requirements with this revenue as I have recommended above. This implies that the net off-system revenues are being shared between APS' retail and wholesale customers, which is not appropriate since APS' owned power supplies were built to serve retail load. If this is correct, APS should modify its revenue allocation methodology to credit all of its net revenues from off-system sales to ACC jurisdictional retail customers only.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

TELLUS INSTITUTE
Resource and Environmental Strategies

RICHARD A. ROSEN

Executive Vice-President
Treasurer
Senior Research Director
Tellus Institute
11 Arlington Street
Boston, MA 02116 USA
Tel. (617) 266-5400
Fax. (617) 266-8303
Email: rrosen@tellus.org

Education

Ph.D.	Physics, Columbia University, 1974
M.A.	Physics, Columbia University, 1969
B.S.	Physics and Philosophy, M.I.T., 1966

Experience

1998-2001	Director of Energy Group, Tellus Institute
1997-present	Manager of Electricity Group, Tellus Institute.
1993-1997	Director of Energy Group, Tellus Institute.
1991-present	Director of Planning, Tellus Institute.
1977-present	Energy Group. Responsibility for a broad range of research on integrated resource planning energy conservation; electric generation planning issues; and modeling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning.
1978-1980	Consultant to Brookhaven National Laboratory.
1979	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976-1978	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974-1976	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.

1973 Instructor, Putney - Antioch Graduate School.

Testimony

Agency	**Case or Docket No.**	**Date**	**Topic**
Arizona Corporation Commission	E-00000A-02 0051 et al.	November 2002	Track B issues
		November 2002	Rebuttal Testimony in above dockets
Public Service Commission of Wisconsin	05-CE-117, 05-CE-130, 05-AE-109 (Tellus 02-070)	August 2002	Review components of Phase I of proposed Power The Future investment plan; recommend changes in assumptions and methodology to improve WEPCO's Application for both Phase I and Phase II
		September 2002	Surrebuttal testimony in above dockets
Arizona Corporation Commission	E-00000A-02-0051 (Tellus 02-072)	May 2002	Market Power in the Context of Deregulated Electricity Markets
Arizona Corporation Commission	E-04345A 01-0822 (Tellus 01-199)	March 2002	Arizona Public Service Company's Request for a Variance of Certain Requirements of A.A.C. R14-2-1606
Arizona Corporation Commission	E-01032C-00-0751 (Tellus 00-172)	February 2002	Citizens Communications Company wholesale purchased power costs
United States District Court for the Southern District of Ohio – Eastern Division	C2-99-1181 (Tellus 00-205)	November 2001	Evaluation of whether Ohio Edison should have forecasted that 11 activities undertaken at W.H. Sammis plant would cause net emissions increases exceeding the allowable Clean Air Act thresholds for SO_2, NO_X, and PM_{10} at the time the activities occurred
		August 2002	Supplemental Expert Testimony in above docket.
Colorado Public	00A-600E	March	Review of evidence filed by Public Service

Utilities Commission	(Tellus 00-204)	2001	Company of Colorado in support of a proposed transmission line and high voltage DC converter between Lamar, CO and Holcomb, KS
Wisconsin Public Service Commission	05-CE-113 (Tellus 99-207)	Nov. 2000	Review and critique of Application supporting construction of Arrowhead-Weston transmission line
		Dec. 2000	Sur-rebuttal Testimony in above docket
Colorado Public Utilities Commission	99A-549E Phase I (Tellus 00-128)	Nov. 2000	Review of the adequacy of PSCo's selection of the electric generation resource bids that it has chosen for its final IRP plan
Colorado Public Utilities Commission	00A-007E (Tellus 00-021)	March 2000	Review of methodologies on which PSCo's summer peak demand and sales forecasts are based, and recommendations how its load forecasting could, and should, be improved
New Hampshire Public Utilities Commission	DE99-099 (Tellus 99-136)	Dec. 1999	Discussion of the Transition Service Energy Charges that might be applied in New Hampshire
New Hampshire Public Utilities Commission	DE 99-099 (Tellus 99-136)	Nov. 1999	Non-rate design aspects of the proposed Settlement Agreement between PSNH and the State of New Hampshire
Delaware Public Service Commission	99-457 (Tellus 99-145)	Nov. 1999	Analysis of the stranded cost-related issues in the Delaware Electric Cooperative, Inc.'s filing and sponsoring of an estimate of stranded costs for the DEC
		Dec. 1999	Rebuttal testimony
Federal Energy Regulatory Commission	EC97-56-000 ER97-4669-000 (Tellus 97-230)	Sept. 1999	Description of, and results of, an independent analysis of market power performed to demonstrate potential impact on regional electricity prices of proposed KCPL/Western Resources merger, and to illustrate several key aspects of how market power analysis for a merger should be done
Arizona Corporation	RE-00000C-	July	The status of settlement discussions between

Commission	94-0165 (Tellus 98-147)	1999	Residential Utility Consumer Office (RUCO) and Citizens Utilities Company-Arizona Electric Division, and summary of concerns about CUC-AED's stranded cost recovery plans
Public Utilities Commission of New Hampshire	DR 96-150 (Tellus 98-237)	June 1999	Clarification of the regulatory policy implications of the New Hampshire Supreme Court decision of December 23, 1998, as it applies to the future recovery of stranded costs in the rates that the PUC will set for Public Service of New Hampshire
Missouri Public Service Commission	Case No. EM-97-515 (Tellus 97-230)	April 1999	Review and critique of the analyses of market power specific to the proposed merger of Kansas City Power & Light Company and Western Resources, performed by Dr. Robert Spann on behalf of the Applicants. Also a description of, and the results of, an independent analysis of market power performed in order to demonstrate the potential impact on regional electricity prices of the proposed merger.
Arizona Corporation Commission	E-01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473 E-01345A-97-0773 and U-00000C-94-165. (Tellus 98-147)	November 1998	Analysis of various filings related to the unbundled service tariffs, stranded cost recovery proposals for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals
New Mexico Public Utility Commission	2867/2868 (Tellus 98-195)	November 1998	Application of Residential Electric Incorporated for a CCN to provide electric service and its request that Public Service of New Mexico offer transmission, distribution, and customer-related services, at unbundled rates
Public Utilities Commission of Nevada	98-7023 (Tellus 98-111)	November 1998	Analysis of stranded generation costs of Sierra Pacific Power Co. and the Nevada Power Co.; analysis of conditions under which competitive wholesale power markets could be created in Nevada, particularly given the severe transmission constraints in the state

Maine Public Utility Commission	97-580 (Tellus 98-007)	May 1998	Central Maine Power's proposed Standby rates and related policy issues
		August 1998	Surrebuttal testimony in above docket
Maine Public Utility Commission	97-580 (Tellus 98-007)	April 1998	Alternative estimate of value of stranded costs of Central Maine Power Company based on three changes to their methodology, and alternative estimate of CMP's non-utility generation stranded costs arising from the Regional Waste Systems purchased power contract
New Hampshire Public Utilities Commission	DR 98-012 (Tellus 98-019)	April 1998	Proposed Offer of Settlement in the Granite State Electric Company restructuring docket
New Mexico Public Utility Commission	2761 (Tellus 97-135)	April 1998	Investigation of the potential of using market pricing for the unbundled generation portion of rates in a way that will allow Public Service Company of New Mexico to realize the fair market value of its generation plant over the long run, beginning with the test year 1996
New Hampshire Public Utilities Commission	DE97-251 (Tellus 98-019)	March 1998	Evaluation of whether or not the proposed transfer of the generating assets and purchased power agreements of the New England Power Company to USGenNE is in the public interest for the citizens of New Hampshire
Arizona Corporation Commission	U-0000-94-165 (Tellus 97-289)	Jan. 1998	Public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; presentation of "retail generation service" methodology for computing stranded costs

		Feb. 1998	Sur-Rebuttal testimony in above docket
New Jersey Office of Administrative Law	BPU EO9707-0465 OAL PUC-7309-97 BPU EO9707-0464 OAL PUC-7310-97 Tellus (97-203/A4)	Jan. 1998	The importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Rockland Electric Company)
		March 1998	Sur-rebuttal Testimony in above docket
New Jersey Office of Administrative Law	BPU E097070 456 OAL PUC 7311-97 (Tellus 97-203/A6)	Nov. 1997	Importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Atlantic City Electric)
New Jersey Office of Administrative Law	BPU EO9707 0459 OAL PUC-7308-97 BPU E09707 0458 OAL PUC-7307-97 (Tellus 97-203/A3)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Jersey Central Power & Light dba GPU Energy)
New Jersey Office of Administrative Law	BPU E09707 0462 OAL PUC-7347-97 BPU EO9707 0461 OAL PUC-7348-97	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Public Service Electric & Gas Company)

	(Tellus 97-203/A1)		
		Jan. 1998	Sur-rebuttal testimony in above dockets
Public Utility Commission of Texas	473-96-2285 and 16705 Tellus 97-046)	Sept. 1997	Competitive issues
Michigan Public Service Commission	U-11283 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test
Michigan Public Service Commission	U-11337 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test
New York Public Service Commission	96-E-0898 (Tellus 97-009)	May 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Rochester Gas and Electric Corp., and public policy recommendations on key issues related to market structure, market power, and the likelihood of RG&E's proposed retail access program actually leading to competition
New York Public Service Commission	96-E-0897 (Tellus 97-009)	April 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Consolidated Edison Company of New York, Inc., and public policy recommendations related to market structure and market power
New York Public Service Commission	96-E-0891 (Tellus 97-009)	February 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of New York State Electric and Gas Company, and public policy recommendations on key issues related to market structure and market power

Missouri Public Service Commission	EM-96-149 (Tellus 96-214)	Nov. 1996	Various issues related to market power
Federal Energy Regulatory Commission	EC96-10-000 (Tellus 96-050F)	Sept. 1996	Review of the joint application of Baltimore Gas & Electric Company and Potomac Electric Power Company for approval of their proposed merger and organization
Maryland Public Service Commission	8725 (Tellus 96-050)	July 1996	Review of the joint application of BGE and PEPCO for approval of their proposed merger and reorganization
Illinois Commerce Commission	95-0551 (Tellus 95-302)	March 1996	Review of joint application of Central Illinois PSC, CIPSCO Incorporated, and Union Electric Company for approval of their proposed merger and reorganization
Vermont Public Service Board	5724 (Tellus 94-064)	July 1994	Review of Central Vermont Public Service's planning for its power supply resources over the past 5 years and its management of its resource portfolio
Illinois Commerce Commission	94-0065 (Tellus 94-112A)	June 1994	Assessment of the extent to which Byron 2, Braidwood 1 and Braidwood 2 nuclear units may be considered used and useful for ratemaking purposes by Commonwealth Edison, and recommendation of an appropriate ratemaking treatment of the units based on this assessment
		July 1994	Rebuttal Testimony in above docket
Kansas Corporation Commission	180,056-U	February 1994	Oral Testimony (no written testimony) on establishment of IRP rules for electric and gas utilities
Public Utilities Commission of Hawaii	7257 (Tellus 93-144A3)	December 1993	Critique of HECO IRP plan. Recommendations re: better and simpler approach to taking environmental externalities into account in integrated resource planning
Arkansas Public Service Commission	93-132-U (Tellus 93-148)	November 1993	Review application of Arkansas Electric Cooperative Corporation (AECC) for a certificate of public convenience and necessity for the

			construction, ownership, operation, and maintenance of a hydro-electric generating facility at Dam No. 2 ("H.S. #2") on the Arkansas River
		January 1994	Sur-Rebuttal Testimony in above docket
Public Utilities Commission of Georgia	4152-U (Tellus 93-100)	August 1993	Review of ratemaking aspects of the Clean Air Act Compliance plans of Georgia Power Company and Savannah Electric and Power Company
Pennsylvania Public Utility Commission	A-110300 F. 051 (Tellus 92-026)	July 1993	Critique of certain aspects of the Joint Applicants' filing with respect to whether the Joint Applicants have satisfied the requirements of the Pennsylvania PUC's siting regulation
Public Utilities Commission of Ohio	91-635-EL-FOR 92-312-EL-FOR 92-1172-EL-FOR (Tellus 92-165)	April 1993	Comments and recommendations re: Cincinnati Gas & Electric Company's integrated resource plan submitted in the Company's 1992 Electric Long Term Forecast Report
Georgia Public Service Commission	4133-U, 4136-U (Tellus 92-078)	October 1992	Review of the need for new capacity on the Georgia Power Company, Savannah Electric & Power Company, and Southern Company system over the next three years, 1992-1995
Public Utilities Commission of Ohio	92-708-EL-FOR 92-1123-EL-FOR (Tellus 92-041A)	September 1992	Comment on Centerior Energy Corporation's integrated resource plan and Clean Air Act compliance plan submitted in the Company's Long Term Forecast Report; specific recommendations for action on behalf of the Company to improve components of its resource and Clean Air Act compliance planning process
Public Service Commission of the State of Georgia	4131-U, 4136-U (Tellus 91-266)	June 1992	Adequacy of the 1992 Integrated Resource Plans of Georgia Power Company (GPC) and Savannah Electric Power Company (SEPCO)

U.S. Bankruptcy Court - Manchester, NH	BK-91-11336 Chapter 11	March 1992	Adequacy of bankruptcy plan filed by New Hampshire Electric Cooperative, Inc.
Public Utilities Commission of Ohio	91-410-EL-AIR (Tellus 91-082)	December 1991	Ratemaking treatment of Cincinnati Gas & Electric Company's 39.63% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Public Utilities Commission of Ohio	92-418-EL-AIR (Tellus 91-091)	December 1991	Ratemaking treatment of Columbus Southern Power Company's 24.20% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Maine Public Utilities Commission	89-193, 89-194, 89-195 (ESRG 89-189B & 90-039)	August 1990	Review of Bangor Hydro-Electric Company's solicitation of bids with a request for proposals dated July 24, 1989, and its approach to the evaluation of the respondents' bids.
New Hampshire Public Utilities Commission	DF 89-085 (ESRG 90-051)	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation: Issues Affecting NH Consumers
		September 1990	Supplemental Testimony in above docket.
Florida Public Service Commission	891345-EI (ESRG 90-017)	April 1990	Rate base treatment of Gulf Power Company's 63-MW ownership share of the Scherer 3 generating unit.
Michigan Public Service Commission	U-9458 (ESRG 89-158)	February 1990	Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan.
Vermont Public Service Board	5330 (ESRG 89-078)	December 1989	Presentation of results of ESRG Study: *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.*
		February 1990	Further Testimony in above Docket

		February 1990	Surrebuttal Testimony in above Docket
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-90A)	October 1989	Recommendations regarding the proper ratemaking treatment for PECo's Limerick 2 nuclear unit.
Florida Public Service Commission	881167-EI (ESRG 89-034)	May 1989	Ratebase Treatment of Gulf Power Scherer 3 Capacity
Federal Energy Regulatory Commission	ER88-630-000 (ESRG 88-153)	April 1989	Pass Through of Performance Incentive Program Charges by New England Power Company
Public Service Commission of the District of Columbia	Formal Case No. 877 (ESRG 88-128D)	February 1989	Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site Proposed by PEPCO
	(ESRG 88-128E)	March 1989	Rebuttal Testimony
Michigan Public Service Commission	U-8871 (ESRG 88-32)	April 1988	Review of the Appropriate Avoided Costs for the CPCo System
	(ESRG 88-32A)	August 1988	Rebuttal Testimony
Maine Public Utilities Commission	87-268 (ESRG 30A)	April 1988	Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power
	87-268 (ESRG 87-30A1)	August 1988	Supplemental Testimony
Pennsylvania Public Utility Commission	M-870111, G-870087 G-870088 (ESRG 88-01)	February 1988	Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs

Pennsylvania Public Utility Commission	R-870732 (ESRG 87-80)	November 1987	Investigation into Pennsylvania Power Company's Share of Perry 1 Nuclear Unit and Assessment of Physical Excess Capacity. Direct and Rebuttal Testimony.
Michigan Public Service Commission	U-7830 (ESRG 85-35E)	December 1987	Review of the Application of Consumers Power Company to Recover Its Midland Investment
Pennsylvania Public Utility Commission	R-870651 (ESRG 87-50D)	October 1987	Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System.
Federal Energy Regulatory Commission	ER-86-694-001	September 1987	Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission
Maine Public Utilities Commission	86-85	June 1987	Investigation of Reasonableness of Rates
		August 1987	Surrebuttal
Maryland Public Service Commission	7972	February 1987	Investigation by the Commission of the Justness and Reasonableness of the Rates of Potomac Electric Power Company
Arizona Corporation Commission	U-1345-85-367 (Tellus 86-42B)	February 1987	Concerning the Prudence of Palo Verde Investment
Michigan Public Service Commission	U-8578 (Tellus 86-055A)	January 1987	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8585	January 1987	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Pennsylvania Public Utility Commission	R-860378 (Tellus 85-083A)	September 1986	Economics of Duquesne Light Company's Share of Perry 1
		November 1986	Surrebuttal

Pennsylvania Public Utility Commission	R-850267 (Tellus 85-083B)	September 1986	Economics of Penn Power's Share of Perry 1
		November 1986	Surrebuttal
		March 1987	Supplemental
Michigan Public Service Commission	U-8348	July 1986	Palisades Performance Standards
Michigan Public Service Commission	U-8291	April 1986	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8286	February 1986	Power Supply Cost Recovery Plan for Consumers Power
Michigan Public Service Commission	U-8297	January 1986	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Michigan Public Service Commission	U-8285	January 1986	Power Supply Cost Recovery Plan for Indiana & Michigan Company
Division of Public Utilities, Dept. of Business Regulation	85-2011-01 85-999-08	January 1986	Construction of a Transmission Line and Transmission Facilities in Southwestern Utah
New York Public Service Commission	28252	October 1985	Shoreham - Rate Moderation
		January 1986	Surrebuttal
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224 (Tellus 83-089)	June 1985	Wolf Creek Excess Capacity and the Prudency of Company Planning
Federal Energy Regulatory Commission	ER-84-560-000 (Tellus	April 1985	Callaway Excess Capacity and a Review of Union Electric Planning

	85-019)		
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U 142-100-U	April 1985	General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas
Michigan Public Service Commission	U-8042	February 1985	Power Supply Cost Recovery Plan for Consumers Power Company
Michigan Public Service Commission	U-8020	January 1985	Power Supply Cost Recovery Plan for Detroit Edison Company
Massachusetts Department of Public Utilities	84-49, 84-50, 84-140, 627, 1656 & 1957	January 1985	Economics of Completing Seabrook 1 for Four Massachusetts Utilities

List of other testimony prior to 1985 available upon request.

Tellus Research

2003 *The August 14, 2003 Blackout in the United States: Technical and Regulatory Issues.* Report to the Swiss Federal Office of Energy. Tellus Study No. 03-185.

2001 *Integrated Resource Planning in Saudi Arabia.* Under contract from the UN Department of Economic and Social Affairs. Tellus Study No. 99-149. Consultant/Advisor to Project Manager.

2001 *Comments on the Interim Pricing Report on New York State's Independent System Operator.* Prepared for the Public Utility Law Project. Tellus No. 00-213. Co-author.

1999 *A Comparison of Studies by U.S. DOE and Stone & Webster on the Effect of Electric Restructuring in Colorado.* A Report Prepared for: National Rural Electric Cooperative Association. Tellus Study No. 99-085. September. Co-author..

1999 *Comments of the OCC to the Colorado Electricity Advisory Panel on Market Power.* The Potential Exercise of Horizontal Market Power in a Deregulated Colorado Electricity Market. Tellus No. 98-124. June. Co-author.

1999 *Funding for Energy-Related Public Benefits: Needs and Opportunities With and Without Restructuring*. A report to the Governor's Office of Energy Conservation. Tellus Study No. 98-002/C2. May. Co-author.

1998 *New England Tracking System (NETS)*. A report of the New England Governors' Conference, Inc. Tellus Study No. 97-063. October. Project manager.

1998	"Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." Comments to Arizona Corporation Commission. Docket No. E-01933A-98-0471. September. Co-author.
1998	"Analysis and Recommendations of Residential Utility Consumer Office Regarding the Arizona Public Service Company's Stranded Cost Filing." Comments to Arizona Corporation Commission. Docket No. E-10345A-98-0473. September. Co-author.
1998	"Analysis and Recommendations of Residential Utility Consumer Office Regarding the Citizens Utilities Company's Stranded Cost Filing." Comments to Arizona Corporation Commission. Docket No. E-1032C-98-0474. September. Co-author.
1998	"Comments on the Missouri PSC Staff's Electric Restructuring Plan and the Retail Electric Task Force Report." Case No. EW-97-245. August.
1998	"Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco," the *Energy Journal.* Vol 19, no. 3. June. Co-author.
1998	*Use of Computer Simulation Models to Analyze Market Power in Electricity Markets.* Comments of Tellus Institute before the Federal Energy Regulatory Commission. Docket No. PL98-6-000. Tellus No. 98-074. June. Co-author.
1997	*Restructuring the Electric Industry in Delaware.* A Draft Report by the Delaware Public Service Commission Staff. PSC Docket No. 97-229. Tellus Study No. 96-099. November. Co-author. Final Draft Report.
1997	*Comments on NEPOOL Executive Committee Market Power Analysis and Mitigation Filings.* A report for: The New England Conference of Public Utility Commissioners (NECPUC). Tellus No. 97-054. July. Co-author.
1997	*Sustainable Electricity for New England: Developing Regulatory and Other Governmental Tools to Promote and Support Environmentally-Sustainable Technologies in the Context of Electric Industry Restructuring.* The R/EST Project. A report to the New England Governors' Conference, Inc. Tellus No. 95-310. January. Project manager.
1996	*Comments on FERC's CRT NOPR in Docket No. RM96-11-000.* Submitted to: The National Association of State Utility Consumer Advocates. Tellus Study No. 96-142. October. Principal investigator.
1996	*Potential Costs and Benefits of Electric Industry Restructuring.* Tellus No. 95-95-190. July. Co-author.

1996 *Achieving Efficiency and Equity in Nevada's Electric Industry - Comments Submitted by the Attorney General's Office of Advocate for Customers of Public Utilities on Issues Posed by the State Assembly in A.C.R. #49 Directing a Study of Competition in the Generation, Sale, and Transmission of Electricity.* Tellus Study No. 95-153A1. January. Co-author.

1995 *Promoting Environmental Quality in a Restructured Electric Industry.* A Report to: The National Association of Regulatory Utility Commissioners. Tellus Study No. 95-056. December. Co-author.

1995 *Power Pools and Least-Cost Compliance with the Clean Air Act.* A Report to: the Pew Charitable Trusts. Tellus Study No. 94-113. October. Principal investigator.

1995 *Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities.* Tellus Study No. 93-251. September. Principal investigator.

1995 Discussion Paper: An Overview of the Generic Issues Related to the Amendment to Illinois Senate Bill 1058. Submitted to the Illinois Consumer Utility Board. Tellus Study No. 95-210. September.

1995 Tellus' Initial Comments on CEEP's Discussion and Conclusions of its Electric Competition Investigation (PA PUC Docket No. I-940032). Submitted to: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-012. September. Co-author.

1995 *Analysis of Economics of the Sherman Biomass Generating Unit.* Prepared for: Wheelabrator Environmental Systems, Inc. Tellus Study No. 95-154. May. Co-author.

1995 *Order on Application for Reconsideration, Formal Case No. 813, Order No. 10590.* Public Service Commission of the District of Columbia. Tellus No. 94-051. March.

1995 *Order on Application for Reconsideration, Formal Case No. 813, Order No. 10554.* Public Service Commission of the District of Columbia. Tellus No. 94-051. January.

1995 In the Matter of a Notice of Inquiry to Consider Section III of the Energy Policy Act of 1992 - Integrated Resource Planning and Energy Efficiency Investments in Power Generation and Supply for Electric Utilities. Docket No. 94-342-U. Prepared for: Arkansas Public Service Commission. Tellus No. 92-153A4. January. Co-author.

1994 *Competition and the Tennessee Valley Authority.* White paper prepared for TVA's Board of Directors. Tellus Study No. 94-096. October. Co-author. Draft.

1994-1995 Independent Advisors to the Tennessee Valley Authority's Board of Directors during the Utility's Development of its First Integrated Resource Plan. Tellus Study No. 94-096. May 1994-December 1995. Project manager.

1994 *Report on Notice of Advanced Rulemaking Relating to Commission Review of Siting and Construction of Electric Transmission Lines.* Submitted to: Pennsylvania Office of

Consumer Advocate. Docket No. L-00940091. Tellus Study No. 94-223. December. Co-author.

1994 "Comments in Response to Edison Electric Institute's Petition for Statement of Policy on the Ratemaking Treatment of the Costs Associated with SO_2 Emissions Allowances." Docket No. PL95-1-000. Federal Energy Regulatory Commission. Tellus Study No. 94-113. November. Co-author.

1994 *Electric Transmission Pricing.* A report to: American Wind Energy Association. Tellus Study No. 94-39. September. Co-author.

1994 *Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings.* Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300. April. Co-author.

1993 *Aligning Rate Design Policies with Integrated Resource Planning.* A report to: National Association of Regulatory Utilities Commissioners. Tellus Study No. 92-047. December. Co-author.

1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 35: Adoption of the Guidelines for Integrated Resource Planning by Electric Cooperatives. Tellus Study No. 93-053. August. Co-author.

1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 39: PURPA Standards as Amended by the Energy Policy Act of 1992. Tellus Study No. 93-054. August. Co-author.

1993 *IRP Concepts and Approaches.* Report to Hydro-Quebec and the Public Interest Groups and Associations. Tellus Study No. 92-155. July. Project manager.

1993 *Proposed Rules Governing Integrated Resource Planning for Electric and Natural Gas Utilities Regulated by the State of Kansas.* In collaboration with Kansas Corporation Commission Staff. Tellus Study No. 92-105. June. Project manager.

1993 *Preliminary Study on Integrated Resource Planning for the Consumers' Gas Company Ltd.* Prepared for Consumers Gas Company, Ltd. Tellus No. 91-001. Project Co-manager. May. Not publicly available.

1992 *Sales Forecasts and Price Changes for New Hampshire Electric Cooperative.* Prepared for: Members Committee of New Hampshire Electric Cooperative. Tellus Project No. 91-173. January. Principal investigator.

1991	*America's Energy Choices: Investing in a Strong Economy and a Clean Environment.* In collaboration with the Union of Concerned Scientists, the American Council for an Energy Efficient Economy, the Natural Resources Defense Council, and the Alliance to Save Energy. Tellus Study No. 90-067. September. Co-author.
1990	*Environmental Impacts of Long Island's Energy Choices: The Environmental Benefits of Demand-Side Management.* Tellus No. 90-028A. September. Co-author.
1990	*Assessment of the Eastern Utilities Associates' Plan to Acquire UNITIL Corporation: Issues Affecting New Hampshire Consumers.* Exhibit 2 to Tellus No. 90-051. July. Project manager.
1990	*Comments on Pacific Power and Utah Power Resource and Market Planning Program.* On behalf of Committee of Consumer Services, Utah Department of Commerce. ESRG No. 90-050A. April. Author.
1990	*The Northeast Utilities Plan for Public Service Company of New Hampshire: Issues Affecting New Hampshire Consumers.* A report to: State of New Hampshire, Office of the Consumer Advocate. ESRG No. 90-019. March. Reviewer.
1989	*The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.* A Report to the Vermont Public Service Board. ESRG No. 89-078. December. Principal investigator.
1989	*Rhode Island's Options for Electric Generation.* A Policy Statement of the Energy Coordinating Council. ESRG No. 89-004. July. Co-author.
1989	*Update of 1985 Study on the Economics of Closing vs. Operating Shoreham.* ESRG Report No. 89-051. March. Principal investigator.
1988	*The Cost to Ratepayers of the Proposed LILCO Settlement.* A Report to Suffolk County. ESRG Report No. 88-23. July. Co-author.
1988	*An Evaluation of Central Maine Power Company's Proposed Purchase of Power from Hydro Quebec.* A Report to the Maine Public Utilities Commission Staff. ESRG Report No. 87-30. April. Principal investigator.

Other Publications

2000 "Electricity Market Regulation in Germany and the USA—History and Prospects," in *Electricity Restructuring and the Environment – A U.S.-German Dialogue.* The Heinrich Böll Foundation, Washington, DC. Co-author.

1992 "Bill Indexing," chapter in: *Regulatory Incentives for Demand Side Management*, edited by S. Nadel, et al. Published by ACEEE/NYSERDA. With David Moskovitz.

Papers and Presentations

2002 "Why the Deregulation of the Electric Industry Will Inevitably Lead to Higher Prices and Lower Economic Efficiency." Washington, DC. September 28.

2002 "How IRP Principles Can Help Explicate Electric Utility Restructuring Issues." A presentation to the NARUC Energy Resource & Environment Committee, NARUC Summer Meeting – Portland, OR. July 30.

2002 "FERC's Standard Market Design: One of the Key Reasons Why Electric Deregulation Will Fail." NASUCA Summer Meeting – Austin, TX , June 16.

2002 NASUCA Seminar on Market Power Issues in the Northeast - Albany, NY, February.

2001 "Just and Reasonable Rates vs. Price Caps at FERC," Backgrounder. June 19.

2001 The Progressive Pro-Consumer Solution to Today's Electricity Crisis: Just and Reasonable Rates. Preliminary proposal to Progressive Caucus, U.S. House of Representatives. May 16. Co-author.

2001 "The Arrowhead-Weston Transmission Line – Issues and Lessons." Presented to: NWCC Upper Midwest Transmission Workshop, Minneapolis, MN. May 1.

2001 "Short- and Long-Term Solutions to Deal with Market Power." Presented at NRRI Market Power Conference, Columbus, OH. April 11.

2001 "Why We Need an ICAP Market in New England." Presented to Massachusetts Electric Restructuring Roundtable, Boston, MA. February 16.

2000 *Can Electric Utility Restructuring Meet the Challenges It Has Created?* A Tellus Institute White Paper. November.

2000 "Electric Restructuring in Crisis: The Implications of Market Power." Pace Conference on Electricity Restructuring. White Plains, NY. November 10.

2000	"Presentation on Market Power Issues Raised by the Proposed NU/Con Edison Merger," to Connecticut DPUC. August 3.
2000	"The Bumpy Launch May Never Stop." NASUCA Conference, Portland, ME. June 5-6. With F. Sverrisson.
1999	"Nothing in the Pipeline?" Some Economic and Environmental Effects of the Proposed Natural Gas Pipeline and Generating Facilities in Southwestern Vermont. With F. Sverrison.
1999	"A Comparison of Studies by U.S. DOE and Stone & Webster on the Effect of Electric Restructuring in Colorado." Presented at Tenth National Energy Services Conference, Tucson, Arizona. December 6-8. With F. Sverrisson.
1999	"The Emperor's New Clothes: Fatal Flaws of the HHI," presented at Pricing Power Products & Services Conferences, Chicago, IL. October 14-15.
1999	"A Better Approach to Market Power Analysis," presented at Annual NECPUC Conference, Bretton Woods, NH. May 25. Revised July 1999. Co-author.
1999	"The Emperor's New Clothes: Fatal Flaws of the HHI," presented at Annual NECPUC Conference, Bretton Woods, NH. May 25.
1999	"Market Power in Colorado." Electricity Advisory Panel. Denver, CO. May.
1998	"Market Power and Mergers," presented at NASUCA Annual Meeting, Orlando, FL. November.
1998	"Breaking Up is Hard to Do, Unless You Have the Power." Presentation to NASUCA Annual Meeting. November 10.
1997	"How Do You Compute Stranded Costs?" A talk to ELCON. Washington, DC. October 30.
1997	"An Overview of Key Issues in Electric Industry Restructuring," presented to the Colorado Office of Consumer Counsel. June 26. Co-author.
1997	"Letting Retail Competition Succeed," presented at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.
1997	"A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," distributed at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.

1997	"A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Panelist.
1997	"Market Power, Mergers, and Deregulation: A Critique of FERC's New Merger Guidelines," The National Regulatory Research Institute *Quarterly Bulletin*. May.
1997	"A Whitepaper On Stranded Costs and Market Structures in the U.S. Electricity Industry," prepared for: The American Association of Retired Persons. Tellus No. 97-009. April. Draft.
1997	"A Point/Counterpoint Analysis of Major Restructuring Issues." Co-author.
1996	"Leveraging" - The Key to the Exercise of Market Power in a Poolco. NARUC and NASUCA Summer Meetings. June. Co-author.
1995	"The Status of Regulatory Policy Affecting the Restructuring of the Electric Utilities Industry." Presentation to: Wheelabrator Technologies, Inc. September.
1995	Presentation to Maine Public Service Company on Behalf of Wheelabrator Sherman to explain Tellus' Calculation of Estimates of Total Avoided Costs for Wheelabrator Sherman Power through 2015. August. Co-author.
1994	"Nine Fallacies in Computing Avoided Costs." Distributed at: The Annual NARUC/ NASUCA Conference, Reno, NV. November. Co-author.
1994	"Apples and Oranges: Using Multi-Attribute Analysis in a Collaborative Process to Address Value Conflicts in Electric Facility Siting." Presented at: Ninth National Association of Regulatory Utility Commissioners (NARUC) Biennial Regulatory Information Conference, Columbus, Ohio, September 8. Co-author.
1993	"How Should Electric Utilities Allocate Their Free EPA-Granted Allowances Among Retail and Wholesale Customers? An Unresolved Issue of Clean Air Act Compliance. Prepared for distribution at: The NARUC/NASUCA 1993 Annual Meetings, New York, NY. November 14. Co-author.
1993	"Integrated Resource Planning and Clean Air Act Compliance: Elements of Consistency." Prepared for Distribution at: The NARUC Energy Conservation Committee 1993 Winter Meeting, Washington, DC. February. Co-author.
1991	"The Clean Air Act Amendments of 1990 and Utility Least Cost Planning: Issues for State Regulators," for distribution at the NARUC Conservation Committee, 1991 Winter Meeting, Washington, D.C. February. Co-author.

1991	"Sustainable Development and the Future of Electric Utilities," for the Energy Conservation Coalition Electric Utility Industry Vision Paper Project, Washington, DC. February.
1989	"Six Fallacies in Computing Avoided Costs," delivered at the NARUC Least Cost Planning Conference, Charleston, S.C. September.
1988	"Ratemaking and Conservation: The Tune Should Fit the Dance," distributed at the NARUC Committee on Energy Conservation Meeting, San Francisco. October 30.
1987	"Electric Utility System Reliability and Reserves" (ESRG Paper). September. Co-author.
1986	"Risk Sharing and the 'Used and Useful' Criterion in Utility Ratemaking" (ESRG Paper). September. Co-author.
1986	"Risk Sharing, Excess Capacity, and the "Used and Useful" Criterion." Presented to the Fifth Biennial Regulatory Information Conference sponsored by the National Regulatory Research Institute in Columbus, Ohio. September.

List of other Publications and Presentations prior to 1985 available upon request.

Related Professional Activities

Elected to Three-Year Term as a member of the Research Advisory Committee of The National Regulatory Research Institute, October 1, 1988 - September 30, 1991. Term extended through June 1992.

Invited Speaker

2001	"Status of Electricity Deregulation Today." Consumers' Assembly – Washington, DC. March 8.
1997	"Evaluating the Competitive Effect of Electric and Gas Utility Mergers Under Retail Competition." Panel - "Merger and Acquisitions: Implications of the Convergence of Electric and Gas Industries," *Current Issues Challenging the Regulatory Process,* Center for Public Utilities, New Mexico State University, Santa Fe, NM. March 11.
1996	"NASUCA's Filing on the CRT NOPR at FERC," NASUCA Annual Conference. November.
1996	"Independent System Operators," NASUCA meeting, Chicago, IL. June.
1995	"Preserving Environmental Quality Under Electric Restructuring," NARUC Energy Conservation Committee meeting, New Orleans, LA. November.
1994	"Electricity Transmission Pricing," presented at NARUC Committee on Energy Conservation, Annual Meeting, Reno, NV. November. Co-author.

1994	Sixth Natural Gas Industry Forum, Quebec City. September 25-28.
1993	The National Energy Summit, in conjunction with the Multi-Media Energy Education Project of the Jefferson Energy Foundation - "Balancing Energy-Environment-Economy (E^3)", Washington, DC. June. Panelist.
1992	"Natural Gas Planning: An IRP Case Study." Presented at: The NARUC Conference on Integrated Resource Planning, Burlington, Vermont, September 13-16. Co-author.
1992	Fourth Natural Gas Industry Forum, Montreal. September.
1992	American Gas Association Long Range Forecasting for Integrated Resource Planning Seminar - "How Externalities and Supply Costs Affect IRP." March.
1991	Edison Electric Institute -- Strategic Planning Committee - "Incorporating Environmental Externalities into Integrated Resource Planning." December.
1990	NARUC Energy Conservation Committee Meeting, Orlando, Florida - "Rate Impacts of Demand-Side Management Programs." November.
1990	NARUC and NASUCA Joint Annual Meeting, Orlando, Florida - "Environmental Externalities and Integrated Resource Planning." November.

10/03

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	)	Docket No. E-A 01345A-03-0437

DIRECT TESTIMONY

OF

DR. JOHN STUTZ

On Behalf of the Arizona
Residential Utility Consumer Office

Tellus Institute
11 Arlington Street
Boston, MA 02116-3411
Tel: 617/266-5400

February 3, 2004

TABLE OF CONTENTS

LIST OF SCHEDULES

1. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is John K. Stutz. My business address is the Tellus Institute (Tellus), 11 Arlington Street, Boston, Massachusetts 02116-3411. I am a vice president at Tellus.

Q. WHAT IS TELLUS?

A. Tellus is a non-profit organization. It provides research and consulting services to clients in the public and private sectors in the areas of energy, environmental policy, solid waste management, water resource planning, and sustainable development.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EMPLOYMENT HISTORY.

A. I received a B.S. from the State University of New York at Stonybrook in 1965 and a Ph.D. from Princeton University in 1969. Both degrees are in mathematics. After completing my Ph.D., I taught and did research at the Massachusetts Institute of Technology, the State University of New York at Albany where I received tenure, and Fordham University where I held the position of associate professor of mathematics and was co-director of the program in mathematics and economics. I left Fordham to join Tellus where I have been employed since 1976.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I have extensive experience in the utility industry, particularly as an expert witness. Since 1977 I have appeared before the Federal Energy Regulatory Commission (FERC) as well as Public Utility Commissions in 39 states, the District of Columbia, and three provinces in Canada. In total, I have appeared in 179 proceedings as shown in Schedule JS-1. Most of my appearances have been in electric utility proceedings. However, I have also testified on gas and telecommunications matters.

In addition to my utility-related activities, since 1988 I have worked regularly for the United States Environmental Protection Agency (EPA), the Organisation for Economic Cooperation and Development (OECD), and various state and local agencies. This work has focused on solid waste management and its impact on the environment.

Q. PLEASE DESCRIBE YOUR BACKGROUND IN UTILITY RATEMAKING.

A. My first appearance as an expert witness on ratemaking was in 1979. Since then, I have appeared as a witness on ratemaking in 121 proceedings, as shown in Schedule JS-1. My testimony has addressed a variety of topics, including marginal costs, embedded cost-of-service studies (COSS), service quality standards, and numerous aspects of rate design. Since the early 1980s, I have testified regularly on behalf of the Rhode Island Division of Public Utilities and Carriers on electric ratemaking issues.

My articles and comments on utility-related subjects have appeared in the *Public Utilities Fortnightly, The Electricity Journal*, and elsewhere. My paper with Thomas Austin is cited, in the second edition of Bonbright's *Principles of Public Utility Rates*, as a source of information on electric ratemaking in general and COSS in particular. I was the lead author of *Aligning Rate Design Policies with Integrated Resource Planning*, a report commissioned and published by the National Association of Regulatory Utility

Commissioners (NARUC). As NARUC's preface states, Tellus was selected to prepare this report largely because of my expertise.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE IN ARIZONA.

A. My first appearance in Arizona was in 1986. Since then I have testified a total of four times in the state. All of my testimony in Arizona has addressed ratemaking. Three of my four appearances were in APS rate cases.

2. SUMMARY AND RECOMMENDATIONS

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses the ratemaking proposals put forward by Arizona Public Service Company (APS or the Company). I will focus primarily on the COSS presented by Mr. Propper, and on the changes in residential class revenue responsibility and rate design he proposes based, in part, on that study. I will also address the changes in Service Schedules proposed by Mr. Rumolo. Dr. Richard Rosen, another witness appearing on behalf of the Residential Utility Consumer Office (RUCO), will address APS' proposals related to the treatment of transmission and fuel and purchased power costs.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. This section presents a summary of my testimony and recommendations. My detailed testimony is presented in the following sections. Section 3 discusses APS' ratemaking proposals. In response to those proposals, Sections 4 to 7 deal with ratemaking principles, COSS methods and results, revenue requirements and rate design. Section 8 addresses APS' proposed changes in the Service Schedules.

Q. WHAT ARE THE KEY POINTS OF YOUR TESTIMONY?

A. My key points are presented below. For convenience they are grouped to correspond to the sections of my detailed testimony.

APS Proposals

- The range of impacts (i.e., increases and decreases) among and within the residential rates produced by APS' ratemaking proposals is substantial. Increases for some small customers are 3.6 to 4.6 times the residential average.
- There are substantial changes in the customer, kWh and kW charges, which adversely affect the price signals sent by APS' residential rates.

Ratemaking Principles

- Bonbright's *Criteria of a Sound Rate Structure* identifies equity and efficiency as primary concerns in ratemaking.
- Mr. Propper only addresses one aspect of equity: cost tracking. Efficiency is never mentioned or discussed.

COSS Methods and Results

- APS' proposed treatment of transmission substantially reduces the returns produced by residential rates.
- In choosing allocators for use in his COSS, Mr. Propper has overemphasized demand and neglected energy. As a result, the residential rates of return produced by Mr. Propper's preferred COSS are unrealistically low, compared to other reasonable COSS.

Revenue Requirements

- APS' allocation of increases among the residential rates is inconsistent with the pattern of rates of return from the Company's preferred COSS.
- Rates of return produced using a more reasonable choice of allocators support equal increases for all the residential rates.

Rate Design

- Mr. Propper's redesign of the residential rates combines selective application of cost tracking with changes based on judgment. The resulting customer impacts are inconsistent with rate stability and are inequitable.
- The price signals created by the residential rates proposed by Mr. Propper discourage conservation and load management, and so are contrary to Bonbright's criterion of efficiency.

Service Schedules

- APS proposed new trip charge and its proposed increases in existing fees reaching 300 percent are contrary to Bonbright's criterion of rate stability.
- APS has proposed line extension allowance that would increase the up-front cost for a 1,000 foot extension by $6,500.
- The proposed change in economic feasibility analysis would make all electric developments more attractive. This conflicts with stated public policy.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. My recommendations are the following:

- APS' proposal to eliminate rates E-10 and EC-1 should be rejected.
- All residential rates should receive the average increase (or decrease) allowed by the Commission for APS as a whole.
- Increases (or decreases) should be accommodated by uniform changes in

usage (i.e., per kWh and kW) and customer charges.

- Customer charges should be stated on a monthly, not a daily basis.
- APS proposed new trip charge should be rejected. Increases in other Schedule 1 charges should be limited to 15 percent.
- The line extension allowance for residential customers should be set at $6,000.
- APS' proposed change in usage assumptions for use in economic feasibility analysis for real estate developments should be rejected.

3. APS PROPOSALS

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S CUSTOMER MIX.

A. APS divides its retail customers into five major classes: Residential, General Service, Irrigation, Outdoor Lighting, and Dusk-to-Dawn Lighting. Information on the number of customers, total usage and average usage per customer for each major class is provided in Schedule JS-2. As that schedule shows, the residential customers are more numerous and have much lower average usage than those in any of the other major classes.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY RATEMAKING.

A. Ratemaking is the process by which a utility's required revenues are translated into the charges which customers pay. Ratemaking involves two steps: development of revenue requirements for individual rates, and the design of charges to recover those requirements.

Q. PLEASE DESCRIBE APS' GENERAL RATEMAKING APPROACH.

A. As Mr. Wheeler, APS' lead witness, explains, APS has assigned the proposed increase on an equal percentage basis to all of the Company's major customer classes. However, specific rates receive greater or lesser than average increases, and individual customers experience larger or smaller than average impacts, based on the Company's ratemaking proposals.

Q. PLEASE DISCUSS THE AVERAGE INCREASES PROPOSED FOR APS' RESIDENTIAL RATES.

A. In addition to two rates for discounted service for which no changes are proposed, APS has five residential rates. As shown on Schedule JS-3, two rates, E-12 and ET-1, account for 80 percent of the customers and about 75 percent of the residential usage. APS' proposed average increases by rate are also shown on Schedule JS-3. APS has proposed average increases varying from 6.6 to 15.5 percent. For rates E-12, ECT-1R and ET-1 these increases reflect Mr. Propper's choices concerning class revenue responsibility. Mr. Propper recommends that E-10 and EC-1 rates be replaced by E-12 and ECT-1R, respectively. The increases for E-10 and EC-1 reflect the proposed elimination.

Q. PLEASE DESCRIBE APS' PROPOSED CHANGES IN THE CHARGES INCLUDED IN RESIDENTIAL RATES.

A. APS has proposed three key changes:

- Customer charges are stated on a daily rather than a monthly basis. Charges for rates E-12, E-10 and EC-1 increase substantially.
- For rates E-12 and E-10, the summer kWh charges are simplified and flattened.
- For rates ECT-1R, ET-1 and EC-1, the ratio of summer on- to off-peak kWh charges is reduced. In the winter, separate on- and off-peak charges are eliminated.

Schedule JS-4 shows the magnitude of the key changes. Schedule JS-5 lists all of the changes proposed by APS for each individual rate.

Q. DO YOU HAVE ANY COMMENTS ON APS' RATE DESIGN PROPOSALS?

A. Yes, I do. The changes APS has proposed are numerous and significant. The impacts they create differ significantly within and among rate classes. The variation in impacts within rates is particularly large.

Schedule JS-6 shows the highest and lowest impacts, by season, for customers on each rate. Comparison with Schedule JS-3 shows that the variation within rates is substantially greater than the variation among rate schedules. Schedule JS-7 provides information on the distribution of impacts by usage level within individual rates. The rates with the largest proposed increases—E-12, E-10, and EC-1—all assign the largest increases to customers at the lowest usage levels.

Q. WHAT QUESTIONS ARE RAISED BY APS' RATEMAKING PROPOSALS?

A. APS' proposed changes raise three sets of questions.

- What principles has APS relied upon to support its proposed changes? Are APS' proposals consistent with the principles it adopted, and with the principles that should guide ratemaking?
- Are APS' proposed average increases reasonable in light of its own COSS results and the results of other reasonable studies?
- Are the impacts of APS' proposed changes in rate design equitable? Do they adversely affect the price signals sent by APS' residential rates?

The following sections of my testimony address these questions.

4. RATEMAKING PRINCIPLES

Q. WHAT GENERAL PRINCIPLES SHOULD GUIDE RATEMAKING?

A. Bonbright's *Criteria of a Sound Rate Structure*, reproduced in Schedule JS-8, provide an appropriate general framework for ratemaking. Among his eight criteria, Bonbright identifies three as primary:

- Opportunity to earn a fair rate of return.
- Equity in the apportionment of costs.
- Efficiency in pricing.

In addition, rate stability, another of Bonbright's criteria, is generally accepted as quite important.

Q. WHAT IS MEANT BY EQUITY?

A. Equity in ratemaking is described in Bonbright's criterion No. 6. It requires fairness in the apportionment of the total cost of providing service among different customers. "Apportionment" refers to the division of the costs, among rates by the setting of revenue requirements, and among customers within a rate by the charges included in that rate. To test whether an apportionment is fair, two points are generally considered:

- Are differences in apportionment based on differences in the cost to serve?
- If differences in apportionment are made clear to ratepayers, are they likely to be accepted?

Customer acceptance is an important aspect of ratemaking. Bonbright indicates this by including public acceptability among the practical attributes of a sound rate structure listed in his criterion No 1.

Q. WHAT IS MEANT BY RATE STABILITY?

A. Rate stability is described in Bonbright's criterion No. 5. It requires that changes in rates result in the minimum of unexpected changes seriously adverse to existing customers. In practice, rate stability is generally interpreted to mean that rates should change gradually.

Q. ARE EQUITY AND RATE STABILITY RELATED?

A. Yes. That relationship is made clear in the following description of an equitable distribution, provided by Payton Young in *Equity in Theory and Practice* (Princeton University Press, 1994).

> As we have seen, the perceived equity of a distribution depends on the particulars of the case: on the nature of the goods being divided, on the salient characteristics of the claimants, on their values and beliefs, and on precedent—on what is normal, customer, and expected in situations of that sort.

In stating that the perceived equity of a distribution depends, in part, on the distribution being what is normal, customary and expected, Dr. Young echoes Bonbright's comment that "the best tax is an old tax."

Q. WHAT IS MEANT BY EFFICIENCY?

A. Efficiency in ratemaking is described in Bonbright's criterion No. 8. It requires rates to be effective in discouraging waste while promoting all justified types and amounts of use. The key to efficiency lies in sending the ratepayer a **price signal** which elicits a balanced response. In addressing efficiency, one needs to consider the way in which customers are likely to respond to the individual charges in a rate, and to the rate as a whole.

Q. HOW ARE EQUITY, EFFICIENCY, REVENUE SUFFICIENCY AND RATE STABILITY ADDRESSED IN THE RATEMAKING PROCESS?

A. Equity is the primary consideration when responsibility for a utility's required revenues is apportioned among the rates. Once an equitable division has been made, efficiency and equity in intra-class apportionment have to be balanced in the design of customer, demand and energy charges applicable to each rate. Rates are designed to recover the share of required revenues allocated to each rate, thus addressing revenue sufficiency. To address stability, changes in both revenue requirements and the charges included in rates are made gradually.

Q. WHAT PRINCIPLES GUIDED THE DEVELOPMENT OF APS' RATEMAKING PROPOSALS?

A. Mr. Propper did not identify a set of principles that guided the development of his ratemaking proposals. However, he did identify three overall objectives which he "kept in mind":

1. Meeting APS' revenue requirement.

2. Improving cost tracking.

3. Unbundling in conformance with the Commission's rules.

Mr. Propper describes "cost tracking" as setting class revenue requirements to produce the system average return and developing customer, demand and energy charges based directly on the unit costs produced by the Company's COSS. COSS tracking is central to Mr. Propper's ratemaking approach. However, Mr. Propper does depart from cost tracking in order to give weight to other factors, particularly rate stability.

Mr. Propper's unbundling proposals focus on the customer charges. Mr. Propper has proposed significant increases in some customer charges in order to fully recover costs for certain services, including billing and metering, which could be provided by parties other than APS.

Q. DO YOU HAVE ANY COMMENTS ON APS' GENERAL RATEMAKING APPROACH?

A. Yes, I have two comments:

- While Mr. Propper does not say much about equity, one aspect of equity—charging customers what it costs to serve them—is addressed by his emphasis on cost tracking. The issues with Mr. Propper's treatment of equity via cost tracking are threefold: (1) his preferred COSS does not provide a reasonable standard for cost responsibility; (2) his tracking is highly selective; and (3) there is more to equity than cost tracking. Customer acceptance is also involved.

- Mr. Propper fails to address, or even mention, pricing efficiency as part of his ratemaking process. In light of the substantial changes he has proposed in design of the residential rates, this is a serious omission.

In the remainder of my testimony, I will focus on equity and efficiency, which Bonbright identifies as primary, and on rate stability, which I and Mr. Propper both find to be important. I will not address revenue sufficiency because any rates approved by the Commission will, of course, be designed to recover the required revenues approved by the Commission.

5. COSS METHODS AND RESULTS

Q. PLEASE DESCRIBE THE ROLE COSS PLAY IN RATEMAKING.

A. Ratemaking involves the setting of revenue requirements and then the development of customer, energy and demand charges applicable to each rate. A COSS produces rates of return which provide part of the basis for setting revenue requirements for each rate. It also produces unit costs that provide part of the basis for setting the charges included in rates.

Q. HOW IS A COSS ORGANIZED?

A. The major steps in a COSS are functionalization, classification, and allocation. To begin, expenses and the costs associated with rate-based items are grouped into functional categories (generation, transmission, distribution, etc.). Next, costs in each of these functional categories are classified as being related to energy usage, peak demand, or the number of customers served by the utility. Finally, based on their classification, costs are allocated among the rate classes using allocation factors.

There is broad agreement among analysts that the three-step procedure of funtionalization, classification and allocation is the proper approach to allocate costs among customer classes. Differences emerge over the classification and allocation of certain costs. Here I will focus on APS' classification and allocation of generation and distribution related costs.

Q. PLEASE EXPLAIN YOUR APPROACH TO THE DEVELOPMENT OF A COSS.

A. The development of a COSS involves choices concerning classification and allocation. It is tempting to think that there is, in each instance, one right choice, and that any other choice is therefore completely wrong. Such a perspective will inevitably distort any serious discussion of COSS development. No COSS is perfect, or even nearly so. However, there are better and worse ways to classify and allocate costs. The goal is to develop a COSS which reflects causal relationships as fully and correctly as possible in its classification and allocation choices.

Q. HOW DO COSS TREAT COST CAUSATION?

A. In a COSS, cost causation is based on **relative use**. Customers are assigned costs associated with the share of utility services and equipment used to serve them. This approach reflects cost causation because, over the long run, utilities construct, maintain, and operate facilities and provide services based as closely as possible on the number of customers they serve, and the demand and usage they face.

Q. IS RELATIVE USE CONSISTENT WITH BONBRIGHT'S CRITERIA OF EQUITY AND EFFICIENCY?

A. Yes. Assigning customers responsibility for the cost of the services and facilities used to serve them, is, on its face, equitable. Rates which assign customers costs based on relative use send customers correct "price signals" concerning the cost associated with their presence on the system, and their demand and consumption. Transmitting this information is consistent with the notion of efficient consumption described in Bonbright's criterion No. 8.

Q. PLEASE DISCUSS THE COSS PRODUCED BY APS.

A. APS produced two COSS. The first COSS treated transmission as APS had treated it in the past. This study was adjusted to reflect the new treatment of transmission proposed by APS. This produced a second, adjusted study, which Mr. Propper has relied upon for ratemaking purposes.

Q. DO APS' TWO COSS PRODUCE SIMILAR RESULTS?

A. No. Unitized rates of return produced by Mr. Propper's preferred study and by the initial, unadjusted COSS are shown in the first two columns of Schedule JS-9. Note the following:

- While the average residential return is similar for both studies, the returns for specific rates are quite different. In particular, the returns for the two rates Mr. Propper proposes to eliminate are above the residential average in the unadjusted study.
- The return for all other (i.e., non-jurisdictional) is substantially lower in the unadjusted study than in Mr. Propper's preferred study.

Dr. Rosen has recommended that APS proposed treatment of transmission be rejected. Consideration of the Company's COSS results supports that view. The results of a COSS should reflect cost causation, not jurisdictional issues as is the case in the APS preferred COSS.

Q. LEAVING ASIDE THE TRANSMISSION ISSUES, DOES APS' PREFERRED COSS FULLY REFLECT COST CAUSATION?

A. No. APS allocation of generation and distribution costs is based solely on demand. To reflect cost causation, these costs should be classified as energy and demand related, and allocated on the basis of energy as well as demand.

Q. HOW DOES APS ALLOCATE GENERATION-RELATED COSTS?

A. The Company allocates these costs using the 4CP method. The only support for the Company's use of this method is the following statement by Mr. Propper:

> Production related and Transmission related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load. Correspondingly, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August, and September.

Q. DO YOU HAVE ANY COMMENTS ON MR. PROPPER'S STATEMENT?

A. Yes, I do. In response to discovery, Mr. Propper agreed that APS does not acquire generation assets and incur the associated costs solely to meet the coincident demand in the four summer months. However, he did not identify the other factors that affect APS' decisions in this area.

Q. DO OTHER WITNESSES ADDRESS APS' GENERATION PLANNING PROCESS?

A. Yes, they do. Mr. Bhatti, the Company's Vice President of Resource Planning, describes APS' approach to system planning as follows:

> The primary goals of APS Resource Planning are to provide our customers with an adequate supply of reliable power at a **reasonable cost** and at a reasonable level of risk. (emphasis added)

Q. HOW IS THE ISSUE OF COST REFLECTED IN THE CHOICE OF GENERATION AND TRANSMISSION RESOURCES?

A. Utility planners can choose different types of generating plants to meet customer loads. Peaking plants offer the advantage of lower capital costs but they are generally more expensive to run. Baseload plants, on the other hand, are more costly to build but have lower running costs. The choice of plant additions requires detailed analysis. However, underlying that analysis is the simple point that utility planners will only build more expensive baseload plants if they produce sufficient operating cost savings to outweigh their higher capital costs. Thus, the additional cost of baseload plants is justified by potential energy cost savings. The same is true for transmission lines. Both their role in meeting peak demand and their capacity to reduce costs by providing access to economic energy sources is considered.

If APS only considered peak demands, then peaking plants would predominate in its generation mix because they are the cheapest plants to build to meet a given demand. However, as Mr. Wheeler, APS' lead witness points out, the APS generation mix contains 44 percent coal as well as 31 percent nuclear units. The cost of coal and nuclear plants cannot be justified solely to meet peak demand.

Q. HOW DO THESE PLANNING CONSIDERATIONS AFFECT THE CLASSIFICATION AND ALLOCATION OF GENERATION- RELATED COSTS?

A. Generating plants are built to meet peak demand, with adequate reserves, and to produce energy at least cost. For investments made to provide energy cost effectively, it is the customer's energy consumption, not their peak demand, that is relevant. Accordingly, generation-related costs should be classified as energy and demand related. Peak demand and energy consumption should be reflected in their allocation.

Q. DOES CONSIDERATION OF RELATIVE USE SUPPORT THE ALLOCATION OF GENERATION-RELATED COSTS BASED ON DEMAND AND ENERGY?

A. Yes. Customers rely on APS' generation and transmission facilities to meet their peak demands and to provide electricity in all the hours. Allocating generation-related costs based solely on demand during the hours of coincident peak demand in June, July, August, and September does not reflect customers' relative use of the system.

Q. HOW DOES THE FAILURE TO ALLOCATE GENERATION RELATED COSTS BASED ON ENERGY AND DEMAND AFFECT COSS RESULTS?

A. The basic effect is to overstate the cost of serving low load factor customers and understate the cost of serving high load factor customers. This point is illustrated in the example presented in Schedule JS-10.

Q. PLEASE DESCRIBE THE EXAMPLE USED IN SCHEDULE JS-10.

A. The example is based on a simple, hypothetical electric utility that has two customers, A and B. A has a constant demand of 100 MW during the period 10 a.m. to 2 p.m. During the remainder of the day its demand is zero. B has a demand of 100 MW all day. These demands are assumed to be the same, 365 days per year, year in and year out. The utility serves its two customers from two generating units; a 100 MW peaker and a 100 MW baseload unit. The plant (i.e., capital) costs and the production costs assumed for the two units are shown in the top position of Schedule JS-10. For simplicity, the example assumes that each of the units can run at 100 percent of capacity with 100 percent reliability at all times.

Q. PLEASE EXPLAIN THE COSTS SHOWN IN THE BOTTOM HALF OF SCHEDULE JS-10.

The bottom half of Schedule JS-10 shows the generation costs allocated to A and B under various assumptions. The schedule begins by establishing bounds on the cost to serve A and B: it would cost **at most** $.08 per kWh to serve A using only the peaker, and **at least** $.05 per kWh to serve B using only the baseload unit. Next the schedule shows the result of applying APS' 4CP method to this example. The cost allocated to A is $.147 per kWh, much more than the cost to serve A using the peaker alone. The cost assigned to B is $.039, less than the cost to serve B from the baseload unit alone. Finally, the schedule shows the result of classifying varying parts of the plant cost as energy-related and allocating it on the basis of usage rather than peak demand. This change in classification eventually moves the costs allocated to A and B into the $.05 to $.08 per kWh range.

Q. PLEASE DISCUSS THE RESULTS SHOWN IN SCHEDULE JS-10.

A. Customer A has a very low load factor, 16.7 percent. B has a 100 percent load factor, the highest possible. The assumption of very different load factors makes the consequences of using different cost allocation methods quite clear. Classification of generation related costs as both energy and demand related results in an equitable cost allocation to customers with differing load factors. Mr. Propper's 4CP method results in a clearly inequitable allocation.

Q. HOW WOULD THE RESULTS OF MR. PROPPER'S PREFERRED COSS CHANGE IF GENERATION RELATED COSTS WERE ALLOCATED ON THE BASIS OF ENERGY AND DEMAND?

A. To address this point I requested that APS rerun Mr. Propper's preferred COSS with the 4CP allocator replaced by the average of 4CP and energy. The results are shown in the third column of Schedule JS-9. Allocating generation-related costs based on energy and demand increases the rate of return for all the residential rates.

Q. TURNING TO A NEW TOPIC, PLEASE DISCUSS THE ALLOCATION OF DISTRIBUTION-RELATED COSTS.

A. Distribution-related costs are the capital costs and operations and maintenance expenditures associated with the transformers, poles, and wires that allows electricity from the transmission system to reach the customer's service drop. Historically, the allocation of these costs has attracted less attention than the allocation of generation-related costs. When one focuses on these costs, an issue come to light: should one classify these costs as demand- and energy-related, as was done for generation-related costs? In my view, distribution costs should be classified as energy and demand related and allocated accordingly.

Classification of part of distribution costs as energy-related is consistent with the principle of relative use. A customer's use of the distribution system is not limited to the few hours of the year when the customer's demand contributes to peak demand. Customers make more or less continuous use of the distribution system to obtain electricity. This being the case, energy and demand should be reflected in the allocation of distribution related costs.

Q. IS IT POSSIBLE TO INTRODUCE ENERGY USE INTO THE ALLOCATION OF DISTRIBUTION COSTS?

A. Yes. To introduce energy, one can average APS allocators based solely on demand with energy. The results of that change are shown in the final column of Schedule JS-9. Allocating both generation and distribution related costs based on energy and demand produces further increases in the residential rates of return.

Q. PLEASE SUMMARIZE THE RESULTS SHOWN IN SCHEDULE JS-9.

A. The results in Schedule JS-9 show three things. First, the results in columns 1 and 2 show that rejecting APS' proposed treatment of transmission, based on the recognition that jurisdictional changes should not be allowed to distort the causal relationships in COSS, would result in higher rates of return for residential rates. The results in columns

3 and 4 show that using energy and demand to allocate generation and distribution costs will also raise residential rates of return. Taken as a whole, the results in Schedule JS-9 show that the returns for the residential rates are better than those shown in Mr. Propper's preferred study.

Second, the results in Schedule JS-9 support rejection of Mr. Propper's proposal that Rates E-10 and EC-1 be eliminated because they produce low rates of return and so may create a burden on other customers. In fact, as the results in columns 1 and 2 of Schedule JS-9 show, the low returns are due to Mr. Propper's transmission-related adjustments to the COSS. In his unadjusted study, these classes produce returns above the residential average. 14.6 percent of APS' residential customers take service on these two rates. Eliminating them would impose increases substantially above the residential average on these customers. A jurisdictional shift in costs does not provide an adequate justification for the imposition of such a burden.

Finally, I would draw the Commission's attention to the dramatic variation in all other (i.e. non-jurisdictional) returns shown in Schedule JS-9. If one accepts the point that energy and demand are relevant to the allocation of generation-related costs, then non-jurisdictional sales are not even covering their full cost, let alone producing a contribution to APS return. The Commission may want to look more closely, to see whether non-jurisdictional sales are priced appropriately.

6. REVENUE RESPONSIBILITY

Q. PLEASE DESCRIBE APS' PROPOSED CHANGES IN REVENUE RESPONSIBILITY.

A. APS has proposed roughly equal increases for all of the major customer classes including residential. However, for the individual residential rates, a wide range of average increases are proposed. Mr. Propper does not explain how the specific increases proposed were developed. The only rationale offered for the proposed increases is improved cost tracking.

Q. ARE MR. PROPPERS PROPOSED INCREASES CONSISTENT WITH COST TRACKING?

A. No, they are not consistent with cost tracking, even if one accepts Mr. Propper's preferred COSS results. For the residential rates, Schedule JS-11 shows the increases proposed by Mr. Propper, and the rates of return, produced by Mr. Propper's preferred COSS. To make it easier to see how the increases and returns vary, each is expressed as a percentage of the residential average. Note the following:

- Rate ECT-1R produces essentially the same return as residential customers as a whole, but receives a much lower than average increase.
- Rates ET-1 and EC-1 produce essentially the same rate of return, but receive substantially different increases.

- Rate EC-1 produces a better (i.e., higher) return than Rate E-10, but receives a greater increase.

The data in Schedule JS-11 do not show cost tracking at the rate level. Indeed, the increases proposed by APS are so far from cost tracking that one must consider them to be essentially the product of "judgment" rather than cost tracking.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that all residential rate schedules receive the average change approved by the Commission for APS as a whole. The "change" could be an increase or a decrease, depending on the Commission's decision concerning the Company's required revenues.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The considerations of rate stability and continuity that Mr. Propper relied upon to support uniform increases for the major customer classes are equally applicable at the rate level. Their application supports my proposal. My proposal is also supported by the results in Schedule JS-9. As the results show, which rates produce returns above or below the residential average varies depending on which COSS one considers. In that situation a uniform change is reasonable.

7. RATE DESIGN

Q. PLEASE BRIEFLY REVIEW THE CHANGES IN RESIDENTIAL RATE DESIGN PROPOSED BY APS.

A. APS proposes three key changes in residential rate design:

- A shift to daily customer charges and substantial increases in some of those charges;
- Flattening of summer season inclining block charges;
- Reduction or elimination of on- to off-peak differentials in energy (i.e. per kWh) charges.

These changes were discussed earlier, in Section 3 of my testimony. Together with other minor changes in rate design, they create impacts on individual customers which vary greatly within each residential rate, as shown in Schedules JS-6 and 7.

Q. HOW DID MR. PROPPER DEVELOP HIS PROPOSED CHARGES?

A. The point of departure for Mr. Propper was his preferred COSS. In his testimony, he states that, if the cost-of-service study were the only consideration for setting rates, the charges in all rates would be the unit costs from the COSS, expressed as demand, energy, and customer charges. However, his proposed charges depart from the unit costs, in part, so that the increases that individual customers experience can be moderated to the extent Mr. Propper finds "reasonable."

Q. WHAT ISSUES ARE RAISED BY MR. PROPPER'S RATE DESIGN PROPOSALS?

A. The customer impacts associated with Mr. Propper's proposals raise issues of rate stability and equity. The changes in the price signals due to his changes raise questions of efficiency.

Q. PLEASE DISCUSS THE RATE STABILITY AND EQUITY ISSUES.

A. In considering rate stability and equity, it is important to recognize that Mr. Propper's proposals rest substantially on **judgment**. Consider Rate E-12. As shown in Schedule JS-5, two key changes are proposed for this rate. First, there is the increase in the customer charge, which Mr. Propper bases directly on unit cost data from the COSS. Second, there is the change in the first and second block charge. That reflects "simplification," not improved cost tracking. A mixture of judgment and cost tracking accounts for APS' redesign of the other residential rates. As I showed earlier, Mr. Propper's proposals concerning revenue responsibility rest primarily on judgment, not cost tracking. Once one pulls together the two steps in ratemaking—setting revenue responsibility and designing the rates—one sees that APS' residential ratemaking as a whole rests substantially on judgment. Judgment is not sufficient justification for Mr. Propper's proposals, given the impacts that the proposals create.

Mr. Propper's proposals result in increases of up to 44.3 percent for some customers and decreases of up to 3.8 percent for others. Variations of this magnitude are contrary to any reasonable notion of rate stability. Because they are due in large part to judgment rather than cost tracking, they are also inequitable, and are likely to be perceived as such.

Q. WHY ARE APS' PROPOSALS LIKELY TO BE PERCEIVED AS INEQUITABLE?

A. A key feature of APS' proposals is the very high increases they create for small residential customers, and the decreases they provide for very large customers. Were customers informed of APS' proposals, particularly for the treatment of small customers, they would be unlikely to find them acceptable. To appreciate this point it is useful to apply the **6:00 News Test**. Simply imagine that the 6:00 PM TV news included the following item:

- Today APS announced that it will share a proposed $85 million increase in the cost of residential electric service by assigning small residential customers 3.6 to 4.6 times the average increase. This will allow the Company to provide large residential customers with a decrease.

In my opinion, the public is likely to see the arrangement described as unacceptable.

Q. PLEASE DISCUSS THE ISSUE OF EFFICIENCY.

A. The key to efficiency lies in sending the ratepayer a price signal which elicits a balanced response. In addressing efficiency, one needs to consider the way in which customers are likely to respond to the individual charges in a rate, and to the rate as a whole. The proposed dramatic increases in customer charges send the customer a price signal to ignore their level and pattern of usage. The other changes proposed by Mr. Propper send similar price signals:

- The flattening of the summer inclining block charges on rates E-12 and E-10 sends the message that increases in usage are less important than they were before.
- The elimination of the winter on- and off-peak charges and the lowering of the summer on-to-off-peak differential sends customers on rates ET-1 and ECT-1R the message that load shifting is less important than previously.

The price signals sent by Mr. Propper's proposed residential rates may adversely affect customer investment in conservation or load management.

Q. PLEASE EXPLAIN YOUR COMMENT ABOUT CUSTOMER CHARGES.

A. In response to an increase in the customer charge, the ratepayers' only option is to pay the higher amount. In contrast, an increase in a charge per kWh or kW provides an opportunity for increased savings for a customer who invests in more efficient equipment or changes consumption patterns.

In considering this point, it is useful to consider the following **Gas Station Example**. Suppose that Arizona "redesigned" gasoline pricing so that there was a fixed charge, say $5, for all gasoline purchases, and a discount on price per gallon. Would such a change help discourage wasteful use while promoting all justified usage, thus making pricing more efficient in the sense Bonbright uses the term? In my opinion, the answer is "no." Instead, increased usage would appear attractive and the impulse to avoid wasteful usage would be undercut. Increasing customer charges dramatically, as APS proposes for rates E-12, E-10, and EC-1, is likely to have the same effect as the change in gasoline pricing in my example: increased usage will become more attractive and the impulse to avoid waste will be undercut.

Q. IS THE ADEQUACY OF CUSTOMER INVOLVEMENT IN CONSERVATION AND LOAD MANAGEMENT A REASONABLE CONCERN?

A. Yes. It is important to understand that now, as in the past, the concern is under-, not over-involvement in conservation and load management. This is made clear in *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, prepared for NARUC by Richard Cowart in 2001. As Mr. Wheeler points out on pages 48 to 50 of his testimony, APS has a number of programs and joint efforts that are designed to inform customers about energy conservation and load management opportunities, and to promote energy efficiency.

Q. WHY ARE THESE APS PROGRAMS AND EFFORTS RELEVANT HERE?

A. It would be inappropriate to make changes in the design of APS' residential rates, such as those proposed by Mr. Propper, which could undercut APS efforts to promote efficiency. To underline this point, I would direct the Commission's attention to the graph of current and anticipated APS load growth provided in Mr. Wheeler's Attachment SMW-2. In the face of the rapid growth shown there, is it reasonable to redesign residential rates to send price signals to ratepayers to reduce their energy conservation and load management efforts? In my view, the answer is "no".

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ABOUT APS' PROPOSED CHANGES IN CUSTOMER CHARGES?

A. Yes, I do. on page 17 Mr. Propper noted that it may be necessary to "revisit" the customer charges proposed in this case. In response to RUCO 16.23 he acknowledged that this might result in changes in the currently proposed charges. Those changes could not be estimated at this time. Under these circumstances, changing charges substantially now is not compatible with Bonbright's criterion of rate stability.

I would also like to comment on Mr. Propper's proposal to change customer charges from a monthly to a daily basis. APS' residential rates are currently quite complex, containing multi-block kWh charges, demand charges and/or time-of-use energy charges. Adding a variable customer charge will simply make it that much harder for customers to discern the price signals sent by these rates. This will make the rates less efficient. In addition, changing to a daily customer charge is contrary to Bonbright's practical criterion of simplicity, and to Mr. Propper's own goal, stated in a response to RUCO 16.17, of developing rates that can be understood by customers.

Q. DO YOU HAVE ANY COMMENTS ABOUT RATES E-12 AND E-10?

A. Yes, I do. In order to appreciate how customers might respond to the price signals provided by these rates, it is useful to look at the average cost of electricity on these rates, currently and with APS' proposed changes. Schedule JS-12 provides this information. To facilitate comparison between average costs before and after APS' proposed changes, the average costs are indexed by dividing by the average cost for 200 kWh per month, the lowest level of usage APS addresses in its bill impact studies.

The graphs in Schedule JS-12 show that APS' proposal enhances the **quantity discount** present in APS' current rates. A quantity discount is created whenever the average cost per kWh declines as usage increases. In the summer, the decline in average costs for the proposed rates is much greater than for the current rates. Thus, the proposed rates offer larger quantity discounts to more of those served on E-12 and E-10. In the winter, the effects are similar, but less dramatic. 52.6 percent of APS' residential customers are served on rates E-12 and E-10. I would ask the Commission whether it finds it reasonable to provide customers served on these rates with enhanced quantity discounts, encouraging greater use particularly in the summer. In my view, the answer is "no."

Q. HOW DO YOU RECOMMEND APS RESIDENTIAL RATES BE REDESIGNED?

A. I recommend uniform increases in all usage (i.e., per kWh and kW) and customer charges. This approach avoids the issues of rate stability and equity, and of efficiency created by APS' proposals.

- All customers on a rate will be affected equally. The extreme impacts on small customers due to APS proposal will be avoided.
- The rates will send the same price signals as are sent by APS' current rates. Adverse impacts on conservation and load management will be avoided.

Q. DO YOU HAVE ANY FINAL COMMENTS ON THE CHARGES INCLUDED IN APS' RATES?

A. Yes, I do. Under the heading of "other cost elements" Mr. Propper addresses a number of charges including the Systems Benefit Charge (SBC) and the Returning Customer Direct Assignment Charge (RCDAC). The Company has been directed by the Commission to address the level of these charges in this proceeding, but has yet to do so. I simply wish to note that I may respond to this portion of the Company's testimony once it is available.

8. SERVICE SCHEDULES

Q. PLEASE BRIEFLY DISCUSS APS SERVICE SCHEDULES.

A. APS' service schedules address the general terms and conditions for utility service and policies on specific issues such as line extensions. I will address certain changes Mr. Rumolo has proposed in Schedules 1 and 3.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 1.

A. APS is proposing a new trip charge to be assessed when an APS employee attempts to provide a customer-requested service, but is unable to provide it for a variety of reasons. APS also proposes to increase certain existing charges, to reflect current costs.

Q. DO YOU HAVE ANY COMMENTS ON MR. RUMOLO'S PROPOSED CHANGES TO SCHEDULE 1?

A. Yes, I do. Mr. Rumolo has proposed the addition of a new fee and increase in existing fees as part of an effort to improve cost tracking. As in other aspects of ratemaking, one must balance the desire for better cost tracking against other legitimate concerns reflected in Bonbright's criteria. Mr. Rumolo's proposals require adjustment to strike this balance.

The criterion of rate stability, particularly the minimization of unexpected changes seriously adverse to existing customers, is particularly relevant when considering the proposed changes in Schedule 1. The new, $17.50 trip charge is certainly an unexpected and adverse change. Further, as shown in Schedule JS-13, a number of proposed increases in existing charges far exceed the average increase in residential rates.

Increases in the range of 80 to 300 percent are certainly adverse to those who will pay them, and are likely to be unexpected as a result of a proceeding in which the average residential increased proposed by APS is less than 10 percent.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE PROPOSED CHANGES IN SCHEDULE 1 CHARGES?

A. I recommend that the new trip charge be rejected and that the increases in existing charges be capped at 15 percent. A fifteen percent increase will send a price signal that costs are increasing, while insuring that customer impacts are reasonable. In making this recommendation I note that insuring reasonable impacts was one of Mr. Propper's rate design goals.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 3.

A. Schedule 3 is APS' line extension policy. The current policy has three main elements: (1) a 1000 foot free allowance for residential extensions, (2) a revenue test for extensions over 1,000 feet when the cost is under $25,000, and (3) an economic feasibility analysis when the cost exceeds $25,000 or the extension is not subject to the footage allowance or revenue test. Under APS' proposal, the footage allowance is replaced by a $3,500 allowance. If the cost exceeds $3,500, but is under $25,000, the customer will be required to make a non-refundable payment to cover the excess. Line extensions costing over $25,000 will be evaluated based on an economic feasibility analysis.

APS is also proposing changes to its current economic feasibility analysis for new real estate developments. In addition to using only distribution revenue and expenses in the analysis, APS is changing the underlying usage assumption. Currently, APS assumes that the customers in a new development are all-electric. Instead, APS proposes to run the economic analysis under a dual-fuel or all-electric basis, depending on the specifics of the development.

Q. WILL APS' PROPOSED CHANGE IN LINE EXTENSION POLICY HAVE A SUBSTANTIAL EFFECT ON RESIDENTIAL CUSTOMERS' COSTS?

A. Yes, it will. As Mr. Rumolo notes, the cost of a typical 1000-foot overhead extension, provided without a customer payment, today, is approximately $10,000. Thus the proposed change could add up to $6,500 to the cost a customer faces for a long line extension.

Q. DO YOU HAVE ANY COMMENTS ON THE PROPOSED CHANGE IN THE LINE EXTENSION POLICY FOR RESIDENTIAL CUSTOMERS?

A. Yes, I do. APS' proposed change to a dollar allowance is reasonable. The issue is at what level should the allowance be set. In considering this point, the nature of APS' service territory needs to be considered. As Mr. Wheeler points out, APS serves a large, sparsely populated area in addition to the urbanized Valley region. On average, APS serves just 19 customers per square mile. In contrast, SRP and Tucson Electric Power – the other two large Arizona electric utilities – serve 233 and 282 customers per square mile, respectively. Mr. Rumolo's suggestion of an allowance similar to that provided by other Arizona utilities is not supported by Mr. Wheeler's remarks.

Q. WHAT ALLOWANCE DO YOU RECOMMEND?

A. I recommend a $6,000 allowance. $6,000 is roughly half way between the approximately $10,000 cost of a 1,000 foot overhead extension, and the average current APS investment per customer of $1,500 cited by Mr. Rumolo. The $6,000 balances the desire to limit the impact of the allowance on current average cost against the need for rate stability.

Q. DO YOU HAVE ANY COMMENTS ON THE PROPOSED CHANGE IN THE ECONOMIC FEASIBILITY ANALYSIS?

A. Yes, I do. The change proposed by Mr. Rumolo will reduce the up-front cost of an all-electric development, compared to an otherwise comparable dual-fuel development. I would simply ask the Commission if this is the price signal that is appropriate to send to developers, and to customers seeking new homes in APS' service territory. In considering this point, it may be useful to reflect a public policy concerning dual-fuel capacity, stated in Title 40, Section F of the Arizona Statutes, which states the following:

> F. Except as provided in subsection G of this section, during the initial construction of a residential structure, electric and natural gas facilities at a minimum shall be installed in and to the structure in a manner that provides the retail energy consumer ultimately residing in the structure with the capability to choose between electricity and natural gas as an energy source for each appliance application.

I would ask the Commission to consider whether approving an economic feasibility test which could lower the "up front" cost of all electric developments is consistent with the requirement to provide choice between gas and electricity.

In my view, the answer is “no.” If APS wished to change its economic feasibility analysis, it should be required to do so in a fashion that does not make all electric developments more attractive.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SUMMARY OF EXPERIENCE
Dr. Stutz's Testimony Before Regulatory Commissions

	Ratemaking	Planning		Ratemaking	Planning
Alabama	1		Minnesota	2	
Arizona	4		Mississippi	1	
Arkansas	1		Nevada	4	3
Canada	9		New Jersey	7	
Colorado	5	4	New York		5
Connecticut	3	3	New Mexico	6	
Delaware	2		New Hampshire	2	
District of Columbia	1		North Carolina	3	
FERC		3	Ohio	5	1
Florida	1	3	Oregon	1	
Georgia		1	Pennsylvania	2	4
Hawaii		1	Rhode Island	20	3
Illinois	1	3	South Carolina	1	
Iowa	1		Tennessee	1	
Kansas	1		Texas	7	1
Kentucky	1		Utah	2	
Louisiana	2		Vermont	3	1
Maine	11	5	Virginia	1	
Maryland	2		Washington		1
Massachusetts	1	4	West Virginia	3	
Michigan	2	12	Wisconsin	1	
				Total Ratemaking	Total Planning
				121	58

OVERVIEW OF APS' MAJOR CUSTOMER CLASSES

	Customer		Usage		Average Use
	Number (Thousands)	Percent of Total	Level (GWH)	Percent of Total	Per Customer (kWh per Month)
Residential	814.7	88.9	10,587	45.1	1,083
General Service	100.2	10.9	12,706	54.2	10,566
Irrigation	.3	0.0	31	.1	7,741
Outdoor Lighting	1.0	.1	101	.4	8,809
Dusk-to-Dawn Lighting	NA	NA	38	.2	NA
Total - Retail	916.2	100.0	23,462	100.0	2,134

AVERAGE INCREASE BY RATE

	Customers (Percent of Total)	Usage (Percent of Total)	Avg. Use Per Month (kWh)	Average Increase (Percent)	Percent of Residential Average
Redesigned Rates:					
E-12	46.0	30.1	708	6.6	68
ECT-1R	5.3	11.4	2,335	7.0	72
ET-1	34.0	44.6	1,420	11.2	115
Rates Proposed For Elimination					
E-10	11.6	8.5	797	14.6	150
EC-1	3.1	5.4	1,899	15.5	159
All Residential	100.0	100.0	1,083	9.7	100

Note: The residential rates in this and the following schedules appear in ascending order, based on the average increases proposed by APS.

KEY CHANGES IN CHARGES PROPOSED BY APS
(Percent Change)

	Level of Customer Charges	Ratio of Summer kWh Block Charges		Ratio of On- to Off-Peak KWh Charges	
		Second to First	Third to First	Summer	Winter
Redesigned Rates:					
E-12	64.4	-39	-23	NA	NA
ECT-1R	0	NA	NA	-9.4	-29.7
ET-1	-1.6	NA	NA	-36.0	-61.0
Rates Proposed For Elimination					
E-10	64.4	-38	-11	NA	NA
EC-1	50.0	NA	NA	63.0	0

CHANGES PROPOSED BY APS: RATE E-12

	Charges		Percent
	Current	Proposed	Change
Customer ($ per Month)	7.50	12.33	64.4
Energy (¢ per kWh)			
Summer			
First 400 kWh	7.376	8.764	18.8
Next 400 kWh	10.281	8.764	-14.8
Additional kWh	11.991	11.006	-8.2
Winter			
All kWh	7.394	7.105	-3.9
Ratio of Summer kWh Block Charges			
Second to First	1.39:1	1.0:1	-39
Third to First	1.63:1	1.26:1	-22

CHANGES PROPOSED BY APS: RATE ETC-1R

	Charges		Percent
	Current	Proposed	Change
Customer ($ per Month)	15.00	15.00	0
Demand ($ per kW)			
Summer	11.33	11.16	-1.5
Winter	8.11	8.12	0.1
Energy (¢ per kWh)			
Summer			
All – Demand Cap	8.912	NA	NA
On-Peak	4.572	5.279	15.5
Off-Peak	2.543	3.248	27.7
Winter			
All – Demand Cap	6.488	NA	NA
On-Peak	3.618	3.069	-15.2
Off-Peak	2.543	3.069	20.7
Ratio: On-to Off-Peak Energy Charges			
Summer	1.80:1	1.63:1	-9.4
Winter	1.42:1	1.00:1	-29.7

CHANGES PROPOSED BY APS: RATE ET-1

	Charges		Percent
	Current	Proposed	Change
Customer ($ per Month)	15.00	14.76	-1.6
Energy (¢ per kWh)			
Summer			
On-Peak	12.815	12.326	-3.8
Off-Peak	4.129	6.209	50.4
Winter			
On-Peak	10.656	6.882	-64.6
Off-Peak	4.129	6.882	66.7
Ratio: On-to Off-Peak Energy Charges			
Summer	3.10:1	1.99:1	-36.0
Winter	2.58:1	1.0:1	-61.0

CHANGES PROPOSED BY APS: RATE E-10

	Charges		Percent
	Current	Proposed	Change
Customer ($ per Month)	7.50	12.33	64.4
Energy (¢ per kWh)			
Summer			
First 400 kWh	6.682	8.764	31.2
Next 400 kWh	9.189	8.764	-4.6
Additional kWh	9.440	11.006	16.6
Winter			
All kWh	7.609	7.105	-7.6
Ratio of Summer kWh Block Charges			
Second to First	1.38:1	1.0:1	-38
Third to First	1.41:1	1.26:1	-11

CHANGES PROPOSED BY APS: RATE EC-1

	Charges		Percent
	Current	**Proposed**	**Change**
Customer ($ per Month)	10.00	15.00	50.0
Demand ($ per kW)			
Summer	9.84	11.16	13.4
Winter	7.06	8.12	15.0
Energy (¢ per kWh)			
Summer			
All – Demand Cap	7.872	NA	
On-Peak	3.827	5.279	37.9
Off-Peak	3.827	3.248	-15.1
Winter			
All – Demand Cap	5.640	NA	NA
On-Peak	3.176	3.069	-3.4
Off-Peak	3.176	3.069	-3.4
Ratio: On-to Off-Peak Energy Charges			
Summer	1.0:1	1.63:1	63
Winter	1.0:1	1.0:1	0

IMPACTS ON INDIVIDUAL CUSTOMERS

	Percent Impacts on Individual Customers				Impacts as Percent of Residential Average Increase	
	----- Summer -----		------ Winter ------			
	High	Low	High	Low	Maximum	Minimum
Redesigned Rates:						
E-12	35.3	-3.7	20.2	-1.1	364	-38
ECT-1R	12.8	4.3	5.0	1.9	132	20
ET-1	13.3	6.4	12.5	5.3	137	56
Rates Proposed For Elimination						
E-10	44.3	18.2	17.9	-3.8	457	-39
EC-1	18.2	10.5	17.4	4.0	187	41
All Residential	35.3	-3.7	20.2	-3.8	457	-39

IMPACTS BY CUSTOMER SIZE - RATES WITH ENERGY CHARGES

Usage (kWh per Month)	Percent Change					
	E-12		E-10		ET-1	
	Summer	Winter	Summer	Winter	Summer	Winter
200	35.3	20.2	44.3	17.9	6.4	5.3
600	13.4	6.7	24.1	4.1	10.4	9.2
1300	1.3	2.0	17.4	-0.6	12.1	11.0
3000	-3.7	-1.1	18.2	-3.8	13.3	12.5

IMPACTS BY CUSTOMER SIZE - RATES WITH ENERGY AND DEMAND CHARGES

Customer Characteristics			Percent Change			
			ECT-1R		EC-1	
Demand (kW)	**Load Factor (Percent)**	**Usage (kWh)**	**Summer**	**Winter**	**Summer**	**Winter**
3	20	438	4.3	1.9	18.2	17.4
3	75	1,643	11.3	4.3	13.6	8.4
15	20	2,190	5.3	2.5	13.0	10.4
15	75	8,213	12.8	5.0	10.5	4.0

Schedule JS-8

CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

6. Fairness of the specific rates in the appointment of total costs of service among the different customers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

Source: James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

UNITIZED RATES OF RETURN PRODUCED BY DIFFERENT COSS

	Study Relied on by APS	APS' Initial Unadjusted Study	Gen. Costs: Energy-and -Demand Allocation	G & D Costs: Energy-and -Demand Allocation
Redesigned Rates:				
E-12	.88	.86	.95	.97
ECT-1R	.70	.74	.70	.70
ET-1	.61	.55	.74	.77
Rates Proposed For Elimination				
E-10	.52	.74	.59	.61
EC-1	.59	.80	.65	.64
All Residential	.69	.70	.78	.80
ACC Jurisdiction	1.00	1.00	1.00	1.01
All Other	1.33	.89	-.37	-.37

AN EXAMPLE SHOWING THE COSTS PRODUCED BY DIFFERENT ALLOCATION METHODS

1. GENERATION-RELATED COSTS BY UNIT

	Plant ($ per kW-yr)	Production ($ per kWh)
Peaker	$30	$.06
Baseload	$350	$.01

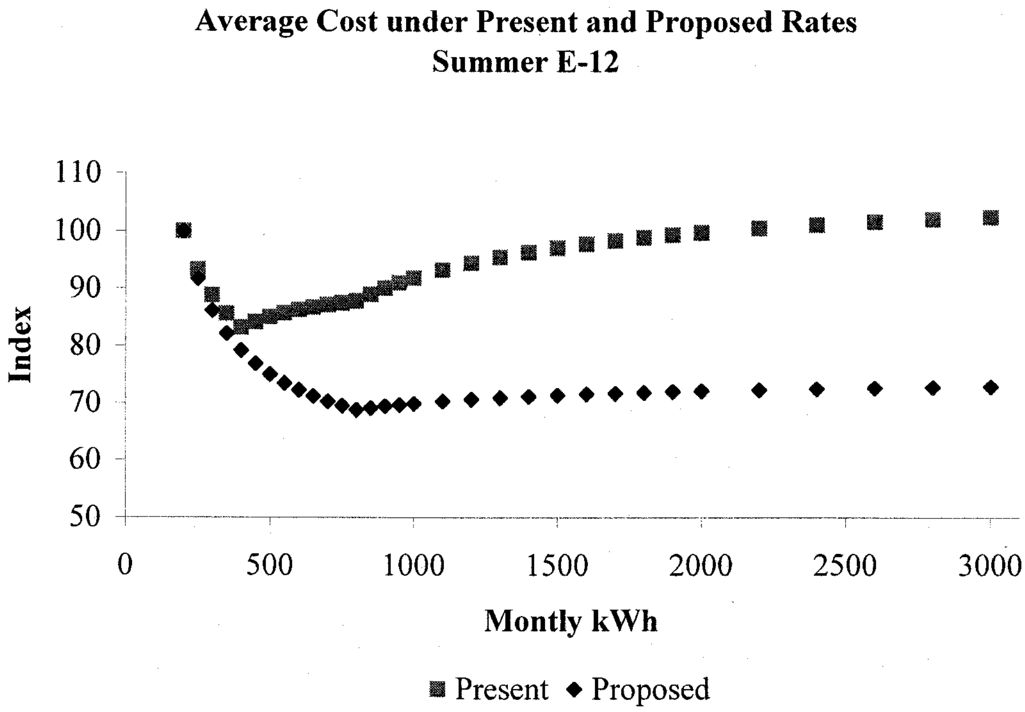
2. GENERATION-RELATED COSTS BY CUSTOMER (Plant and Production, $ per kWh)

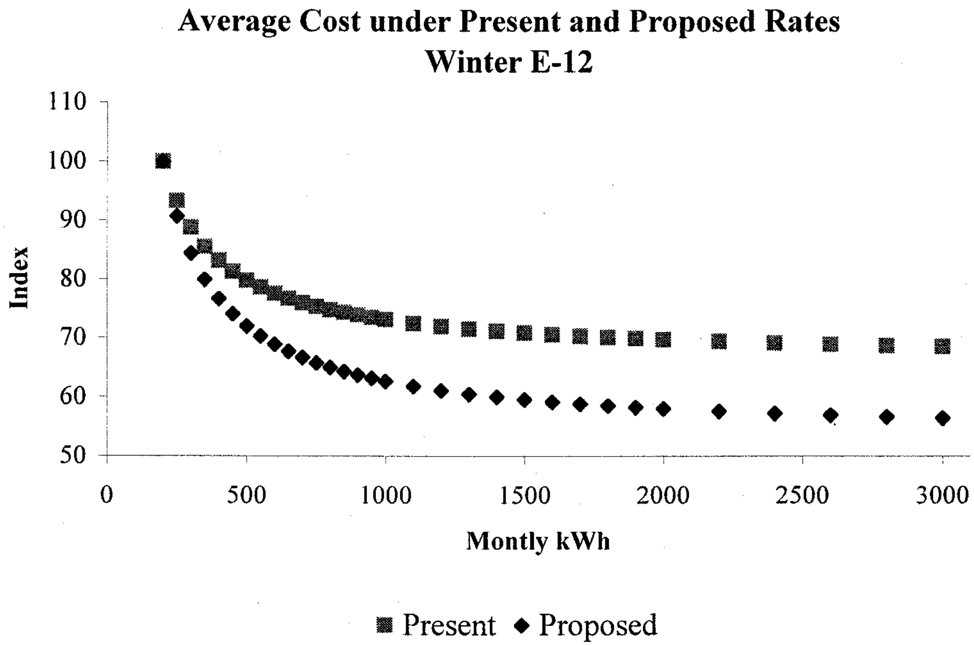
	A Served by Peaker B by Baseload	4CP Used by APS	Average of 4CP and kWh Usage 20% Usage	50% Usage	80% Usage
A	0.0800	0.1473	0.1287	0.1008	0.0729
B	0.0500	0.0388	0.0419	0.0466	0.0512

RESIDENTIAL INCREASES AND RATES OF RETURN
(Percent of Residential Average)

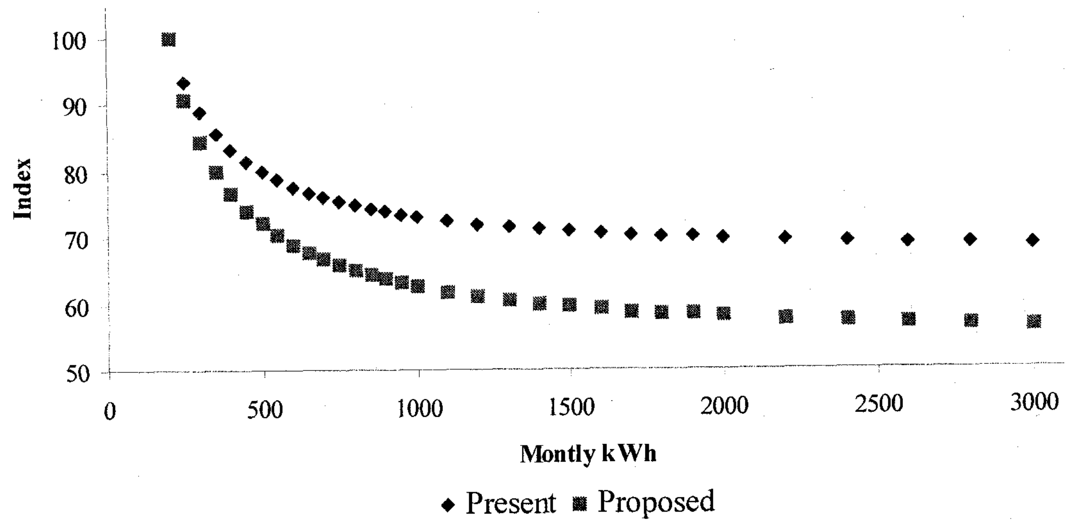
	Increase Proposed	Rate of Return
Redesigned Rates:		
E-12	68	127
ECT-1R	72	101
ET-1	115	87
Rates Proposed For Elimination		
E-10	151	75
EC-1	160	86
All Residential	100	100

AVERAGE COST UNDER PRESENT AND PROPOSED RATES

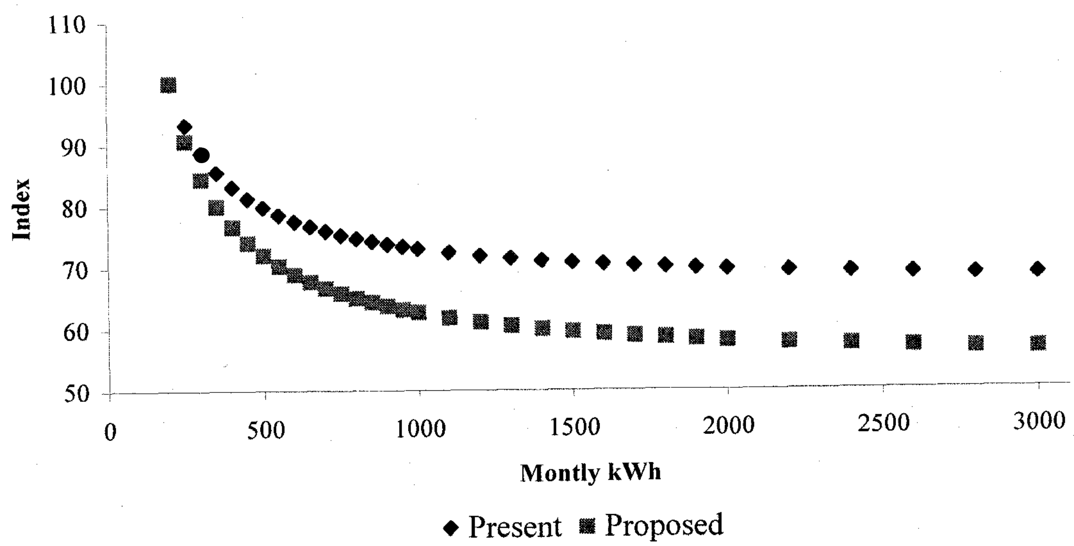




Average Cost under Present and Proposed Rates
Summer E-10



Average Cost Index under Present and Proposed Rates
Winter E-12



Schedule JS-13

PROPOSED CHANGES IN CHARGES FOR SPECIFIC SERVICES

Service	Charge		Change	
	Current	Proposed	Amount	Percent
Trip Charge	None	$17.50	$17.50	NA
Services Outside Normal Business Hours:				
Metric Read, Turn On, or Install Service	$50.00	$75.00	$25.00	50
Other Services	$50.00	$100.00	$100.00	200
Reconnection at Pole	$87.50	$100.00	$12.50	14.3
On Site Energy Evaluation	$50.00	$90.00	$40.00	80.0
Joint Site Visit:				
Metro	$30.00	$70.00	$40.00	133.3
Outside	$75.00	$70.00	-$5.00	-6.6
After 30 mins.	$30/hour	Actual	NA	NA
Meter Test:				
Shop	$25.00	$30.00	$5.00	20
Field	$25.00	$100.00	$75.00	300

REDACTED

ARIZONA CORPORATION COMMISSION

IN THE MATTER

of the
Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract

Docket No. E-01345A-03-0437

Direct Testimony of
David A. Schlissel

On behalf of
The Residential Utility Consumer Office

February 3, 2004

Q. Mr. Schlissel, please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Staff of the Kansas State Corporation Commission, the Arkansas Public Service Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and

Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

Q. Mr. Schlissel, have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified in Dockets Nos. U-1345-85, U-1345-90-007, and E-01345A-01-0822. I also filed testimony in Docket No. U-1551-93-272 but that case was settled before hearings were held.

Q. What is the purpose of your testimony.

A. Synapse was retained by RUCO to evaluate Arizona Public Service Company's ("APS" or "the Company") request that the depreciated cost of the five units built by the Pinnacle West Energy Corporation ("PWEC")[1] be included in its rate base and that the costs related to these units be afforded cost-of-service ratemaking treatment. This testimony presents the results of our evaluation.

Q. Please explain how Synapse conducted its investigations and analyses in this proceeding.

A. We first reviewed APS's Application and the testimony and supporting materials appended to the Application. We also submitted discovery to APS and reviewed the materials that were provided in response to RUCO's data requests and to the discovery requests submitted by the other active parties to this proceeding. In particular, we examined the Applicant's economic analyses concerning the five PWEC generating units and the various planning studies prepared by APS since 1995.

We also reviewed materials from ACC Docket No. E-01345A-01-0822 concerning APS's proposed 28 year power purchase agreement with PWEC

---

[1] Redhawk Units 1 and 2, West Phoenix Unit 4, West Phoenix Unit 5, and Saguaro Combustion Turbine Unit 3.

covering the same five generating units that the Company is seeking to ratebase in this proceeding.

Finally, we reviewed the transmission studies prepared for the ACC Staff as part of the past two biennial transmission reviews.

Q. Please summarize your findings.

A. I have found that:

1. The fact that APS has received and is presently receiving power under contract from the PWEC units is not sufficient evidence, on its own, to demonstrate that APS should be allowed to acquire and ratebase the units. Instead, in the current situation, APS must show that acquiring and placing the five PWEC units into rate base is the most economic of the reasonable alternatives available to the Company at this time and will produce economic benefits for ratepayers within a reasonable period of time.

2. PWEC is being compensated for the capacity and energy it is selling to APS pursuant to the contracts entered into as part of last year's Track B capacity solicitation.

3. APS has not provided any evidence showing that the PWEC units represent the most economic capacity it could acquire in the market.

4. Ratebasing the PWEC units would not produce any annual economic benefits for ratepayers until 2011, seven years after they would have been added to APS's rate. By 2011, ratebasing of the PWEC units would have cost ratepayers an additional $187 million in current year dollars, $169 million in present value 2004 dollars.

5. Ratebasing the PWEC units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until sometime around the years 2018 or 2019.

6. Ratebasing the Redhawk units would not produce an annual economic savings for ratepayers until 2011, seven years after they would have been

ratebased. In addition, ratebasing the Redhawk units would not produce a cumulative present value savings for ratepayers, that is, breakeven, until the year 2020 or 2021.

7. Ratebasing West Phoenix Unit 4 would not produce an annual economic savings for ratepayers until the year 2012, eight years after it would have been ratebased. In addition, ratebasing West Phoenix Unit 4 would not produce a cumulative present value savings for ratepayers until significantly beyond the year 2022.

8. Ratebasing West Phoenix Unit 5 would only produce an annual economic savings for ratepayers in two of the first six years that the unit would be in ratebase. Moreover, ratebasing West Phoenix Unit 5 would not produce a cumulative present value savings for ratepayers, that is, breakeven, until the year 2018.

9. Ratebasing the Saguaro CT would produce an annual economic savings for ratepayers in 2007 and a present value cumulative economic savings by 2009.

10. Even if APS is able to produce a study which projects that the PWEC units might be expected to produce an overall net life cycle economic benefit despite large losses in the early years, that showing would not justify the plants as economic investments today. The timing and magnitude of the losses expected in the near future would have to be considered as well. It would be unfair to make the Company's current customers pay substantially higher rates during near-term years when there is only a remote possibility that they or future generations of ratepayers will see an overall savings from the units until two decades in the future, if at all.

11. Available evidence suggests [

]

12. Numerous APS and PWEC planning studies from the years 1998-2002 indicated that the PWEC units were being built to facilitate power sales to areas outside Arizona, not primarily to serve APS load.

13. [ ]

14. The PWEC units were built in locations where they could serve APS loads and supply power to markets outside Arizona.

15. It appears that in order to improve its ability to sell power in the regional markets PWEC built a resource mix with more baseload combined cycle capacity and less peaking capacity than would have been needed just to serve the growing APS loads.

16. More than 70 percent of APS's current generation units are baseload capacity. This is a very baseload-heavy capacity mix, especially for a Company that traditionally has had a fairly low load factor due to extreme summer temperatures and the relative lack of a substantial industrial process baseload. Approximately 94 percent, i.e., 1,600 MW, of the PWEC capacity that APS is now seeking to acquire also is baseload combined cycle capacity. Only the 79 MW from the Saguaro CT3 represents peaking capacity.

17. [ ]

18. The limited number of hours that APS needs RMR capacity in the Phoenix Valley load pocket and the [ ] that APS currently projects for the West Phoenix and Redhawk units suggest that some of the new capacity needed by APS should have been single cycle turbines instead of baseload combined cycle.

19. There is no capacity crisis requiring the Commission to act at this time to allow APS to acquire the PWEC units and to include them in rate base.

20. The information provided by APS in its January 27 2004 Summary of Responses Received to its Power Supply Request for Proposals about the bids it has received is far too cursory to enable the Commission to evaluate whether the PWEC units represent the most economic capacity that it could acquire in the market. APS has provided no information on the prices and durations of the individual bids. Nor has APS indicated the gas price forecast it has used to develop the range of levelized costs presented in the Summary. This information is essential in order to compare the economic savings and costs from acquiring the PWEC units against the capacity options bid in response to APS's Request for Proposals.

21. For these reasons, the Commission should deny APS's request to acquire and ratebase the PWEC units.

22. Instead of allowing APS to add the PWEC units, the Commission should require that APS immediately undertake the development of a least-cost plan that includes a portfolio of demand-side, generation and transmission options. As part of this plan, APS should be required to undertake a competitive bidding process for power supply contracts (short, medium and long-term) and the purchase of part or all of existing generation facilities. This plan should be developed in order to be in place immediately following the end of the Track B contracts in 2006 or sooner, if possible. PWEC could bid in this competitive process.

23. Planned transmission system upgrades suggest that merchant generators will be able to supply power to APS in the Phoenix load pocket in place of the PWEC units.

Q. Do you agree with the claim by APS witness Bhatti that the test applied by Commission when determining whether to include Palo Verde in the Company's rate base also should apply to the instant situation with the five PWEC generating units?[2]

A. No. The current situation is not analogous to that faced by the Commission in Docket No. U-1345-90-007 concerning the Palo Verde nuclear power plants. Palo Verde had been built by APS, a regulated company, and, at the time it was requesting rate base treatment APS already owned shares of each of the three Palo Verde units. The question before the Commission then was how much of APS's share of Palo Verde capacity was used and useful in the test year.

In contrast, APS in this Docket is seeking Commission approval to both acquire and place into rate base the five PWEC units. In this situation, APS must show that acquiring and placing the five PWEC units into rate base is the most economic of the reasonable alternatives available to the Company at this time and will produce economic benefits for ratepayers within a reasonable period of time.

The current situation is analogous to a Company seeking Commission approval to enter into a life-of-asset capacity purchase agreement except that APS wants to acquire the units from its affiliate PWEC and place their cost into rate base. The Commission previously has declined to approve a request by APS to enter into a long-term power purchase agreement with PWEC. APS is now seeking to achieve the same goal by acquiring the units outright from PWEC.

As a result of the deregulation of the wholesale market APS currently has options that were not on the table when then Commission addressed Palo Verde in Docket

---

2 Testimony of Ajit Bhatti, at page 8, line 22, to page 9, line 7.

No. U-1345-90-007 back in 1991. APS's requested ratebasing of the PWEC units must be weighed against these available alternatives.

The PWEC units represent new resources for APS, the regulated utility, and as such, their acquisition should be evaluated in the same way that resources procured by APS from a non-affiliated company would be judged – that is, subject to a prudence standard viewed from today's perspective. The used and useful test, a legitimate regulatory standard, would only apply after a prudence test was satisfied.

Thus, APS must show that the capacity it is seeking to acquire is the most economic capacity now available in the market and that this capacity will produce net economic benefits for ratepayers within a reasonable period of time.

Q. Do you agree that the PWEC units are actually being used to provide power to APS's customers?

A. Yes.

Q. Is PWEC being compensated for the power it is providing to APS?

A. Yes. PWEC is being fairly compensated for the capacity and energy it is selling to APS pursuant to the contracts entered into as part of last year's Track B capacity solicitation.

Q. Has APS provided any evidence showing that the PWEC generating units represent the most economic capacity it could acquire in the existing market?

A. No.

Q. Have you seen any evidence that the acquisition of the PWEC units will provide net economic benefits for APS's ratepayers within a reasonable number of years?

A. No. In fact, the evidence we have seen suggests that, if the PWEC units are ratebased, the Redhawk and the West Phoenix Units will not produce net economic savings for ratepayers until a decade or two into the future.

Q. Please explain.

A. As shown in Tables 1 through 5 below, we have compared the annual revenue requirements resulting from the ratebasing of the PWEC units and the total annual market revenues associated with these units. These total market revenues represent what it would cost for APS to purchase from the market the same amounts of capacity and energy that would be provided by each of the PWEC units. These comparisons show the net costs/savings from ratebasing the units.

Table 1 shows that:

- Ratebasing the PWEC units would not produce any annual economic benefits for ratepayers until 2011, seven years after they would have been added to APS's rate. By 2011, ratebasing of the PWEC units would have cost ratepayers an additional $187 million in current year dollars, $169 million, in present value 2004 dollars.
- Ratebasing the PWEC units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until sometime around the years 2018 or 2019.

Table 1: The Economic Costs and Benefits of Ratebasing the PWEC Units

	Redhawk Annual Savings/(Costs) Current Year $ ($000)	West Phoenix Unit 4 Annual Savings/(Costs) Current Year $ ($000)	West Phoenix Unit 5 Annual Savings/(Costs) Current Year $ ($000)	Saguaro CT3 Annual Savings/(Costs) Current Year $ ($000)	All Units Annual Savings/(Costs) Current Year $ ($000)	All Units Cumulative Savings/(Costs) Current Year $ ($000)	All Units Annual Savings/Costs PV @ 8.25% ($000)	All Units Cumulative Savings/(Costs) PV @8.25% ($000)	All Units Annual Savings/Costs PV @ 7.07% ($000)	All Units Cumulative Savings/(Costs) PV @7.07% ($000)
2004	(28,503)	(3,363)	(12,863)	(1,093)	(45,822)	(45,822)	(45,822)	(45,822)	(45,822)	(45,822)
2005	(66,579)	(7,139)	(28,853)	(1,785)	(104,356)	(150,178)	(96,403)	(142,225)	(97,465)	(143,287)
2006	(4,622)	(2,237)	1,461	(240)	(5,638)	(155,817)	(4,812)	(147,037)	(4,918)	(148,206)
2007	(9,676)	(1,849)	5,321	576	(5,628)	(161,445)	(4,437)	(151,474)	(4,585)	(152,791)
2008	(10,558)	(1,645)	(2,422)	1,840	(12,786)	(174,230)	(9,311)	(160,785)	(9,729)	(162,519)
2009	(9,004)	(1,653)	(2,374)	1,974	(11,056)	(185,286)	(7,438)	(168,223)	(7,857)	(170,377)
2010	(11,076)	(324)	6,783	2,758	(1,859)	(187,146)	(1,156)	(169,378)	(1,234)	(171,611)
2011	5,970	(491)	5,917	3,030	14,427	(172,719)	8,283	(161,096)	8,943	(162,668)
2012	17,006	178	7,692	3,235	28,112	(144,607)	14,910	(146,186)	16,276	(146,392)
2013	1,668	156	10,237	2,577	14,638	(129,970)	7,172	(139,015)	7,915	(138,477)
2014	25,213	(2,107)	12,129	3,159	38,394	(91,576)	17,377	(121,637)	19,390	(119,086)
2015	19,881	203	8,316	3,194	31,594	(59,982)	13,210	(108,428)	14,902	(104,184)
2016	21,135	(678)	11,028	3,223	34,707	(25,275)	13,405	(95,022)	15,290	(88,894)
2017	6,718	(138)	8,959	2,774	18,313	(6,963)	6,534	(88,488)	7,535	(81,359)
2018	38,499	1,724	19,129	3,601	62,953	55,990	20,750	(67,738)	24,192	(57,168)
2019	50,831	3,992	29,569	4,732	89,124	145,114	27,138	(40,600)	31,987	(25,181)
2020	64,902	6,276	37,947	6,168	115,293	260,406	32,431	(8,169)	38,647	13,467
2021	90,961	8,193	48,064	5,896	153,113	413,519	39,787	31,617	47,936	61,402
2022	74,538	7,758	47,927	6,362	136,586	550,105	32,787	64,404	39,938	101,340

Tables 2 through 5 show that:

- Ratebasing the Redhawk units would not produce an annual economic savings for ratepayers until 2011, seven years after they would have been ratebased. In addition, ratebasing the Redhawk units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until the year 2020 or 2021.

- Ratebasing West Phoenix Unit 4 would not produce an annual economic savings for ratepayers until the year 2012, eight years after it would have been ratebased. In addition, ratebasing West Phoenix Unit 4 would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until significantly beyond the year 2022.
- Ratebasing West Phoenix Unit 5 would only produce an annual economic savings for ratepayers in two of the first six years that the unit would be in ratebase. Moreover, ratebasing West Phoenix Unit 5 would not produce a cumulative present value savings for ratepayers, breakeven, until the year 2018.
- Ratebasing the Saguaro CT would produce an annual economic savings for ratepayers beginning in 2007 and a present value cumulative economic savings by 2009.

Table 2: The Economic Costs and Benefits of Ratebasing Redhawk Units 1 and 2

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	91,546	120,049	(28,503)	(28,503)	(28,503)	(28,503)	(28,503)
2005	158,993	225,572	(66,579)	(61,505)	(90,008)	(62,183)	(90,686)
2006	232,826	237,448	(4,622)	(3,944)	(93,952)	(4,032)	(94,717)
2007	240,928	250,604	(9,676)	(7,628)	(101,580)	(7,883)	(102,600)
2008	288,579	299,137	(10,558)	(7,689)	(109,269)	(8,034)	(110,634)
2009	279,780	288,784	(9,004)	(6,058)	(115,327)	(6,399)	(117,033)
2010	274,327	285,403	(11,076)	(6,884)	(122,210)	(7,352)	(124,384)
2011	276,394	270,424	5,970	3,428	(118,783)	3,701	(120,683)
2012	308,302	291,296	17,006	9,019	(109,763)	9,846	(110,837)
2013	307,160	305,492	1,668	817	(108,946)	902	(109,935)
2014	330,672	305,459	25,213	11,412	(97,534)	12,733	(97,202)
2015	324,324	304,443	19,881	8,312	(89,222)	9,378	(87,824)
2016	340,372	319,237	21,135	8,163	(81,059)	9,311	(78,514)
2017	363,802	357,084	6,718	2,397	(78,662)	2,764	(75,749)
2018	373,173	334,674	38,499	12,690	(65,972)	14,794	(60,955)
2019	385,951	335,120	50,831	15,478	(50,494)	18,244	(42,711)
2020	413,798	348,896	64,902	18,256	(32,238)	21,756	(20,956)
2021	430,499	339,538	90,961	23,636	(8,601)	28,478	7,522
2022	431,581	357,043	74,538	17,893	9,291	21,795	29,317

Table 3: The Economic Costs and Benefits of Ratebasing West Phoenix Unit 4

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	7,934	11,297	(3,363)	(3,363)	(3,363)	(3,363)	(3,363)
2005	14,307	21,446	(7,139)	(6,595)	(9,959)	(6,668)	(10,031)
2006	19,982	22,219	(2,237)	(1,909)	(11,868)	(1,952)	(11,983)
2007	20,773	22,622	(1,849)	(1,458)	(13,326)	(1,506)	(13,490)
2008	23,159	24,804	(1,645)	(1,198)	(14,524)	(1,252)	(14,741)
2009	22,454	24,107	(1,653)	(1,112)	(15,636)	(1,175)	(15,916)
2010	24,563	24,887	(324)	(201)	(15,837)	(215)	(16,131)
2011	23,668	24,159	(491)	(282)	(16,119)	(304)	(16,435)
2012	26,569	26,391	178	95	(16,025)	103	(16,332)
2013	26,266	26,110	156	76	(15,948)	84	(16,248)
2014	29,327	31,434	(2,107)	(954)	(16,902)	(1,064)	(17,312)
2015	27,055	26,852	203	85	(16,817)	96	(17,216)
2016	29,731	30,409	(678)	(262)	(17,079)	(299)	(17,515)
2017	33,614	33,752	(138)	(49)	(17,129)	(57)	(17,572)
2018	30,940	29,216	1,724	568	(16,560)	663	(16,910)
2019	29,551	25,559	3,992	1,216	(15,345)	1,433	(15,477)
2020	29,423	23,147	6,276	1,765	(13,579)	2,104	(13,373)
2021	31,469	23,276	8,193	2,129	(11,451)	2,565	(10,808)
2022	32,584	24,826	7,758	1,862	(9,588)	2,269	(8,540)

Table 4: The Economic Costs and Benefits of Ratebasing West Phoenix Unit 5

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	60,515	73,378	(12,863)	(12,863)	(12,863)	(12,863)	(12,863)
2005	102,430	131,283	(28,853)	(26,654)	(39,517)	(26,948)	(39,811)
2006	133,516	132,055	1,461	1,247	(38,270)	1,275	(38,536)
2007	138,079	132,758	5,321	4,195	(34,075)	4,335	(34,201)
2008	130,823	133,245	(2,422)	(1,764)	(35,839)	(1,843)	(36,044)
2009	151,192	153,566	(2,374)	(1,597)	(37,436)	(1,687)	(37,731)
2010	156,015	149,232	6,783	4,215	(33,221)	4,502	(33,229)
2011	157,661	151,744	5,917	3,397	(29,824)	3,668	(29,561)
2012	163,714	156,022	7,692	4,080	(25,744)	4,454	(25,107)
2013	176,538	166,301	10,237	5,016	(20,728)	5,536	(19,572)
2014	168,718	156,589	12,129	5,489	(15,239)	6,125	(13,446)
2015	175,390	167,074	8,316	3,477	(11,762)	3,923	(9,524)
2016	180,352	169,324	11,028	4,259	(7,502)	4,858	(4,666)
2017	188,738	179,779	8,959	3,197	(4,306)	3,686	(979)
2018	195,343	176,214	19,129	6,305	2,000	7,351	6,372
2019	203,894	174,325	29,569	9,004	11,003	10,613	16,984
2020	220,655	182,708	37,947	10,674	21,677	12,720	29,704
2021	242,753	194,689	48,064	12,489	34,167	15,047	44,752
2022	234,023	186,096	47,927	11,505	45,671	14,014	58,765

Table 5: The Economic Costs and Benefits of Ratebasing Saguaro CT3

	Total Market Revenues ($000)	Total Revenue Requirements ($000)	Annual Savings/(Costs) Current Year $ ($000)	Annual Savings/Costs PV @ 8.25% ($000)	Cumulative Savings/(Costs) PV @8.25% ($000)	Annual Savings/Costs PV @ 7.07% ($000)	Cumulative Savings/(Costs) PV @7.07% ($000)
2004	2,799	3,892	(1,093)	(1,093)	(1,093)	(1,093)	(1,093)
2005	5,792	7,577	(1,785)	(1,649)	(2,741)	(1,667)	(2,760)
2006	8,824	9,064	(240)	(205)	(2,947)	(210)	(2,969)
2007	8,453	7,877	576	454	(2,492)	469	(2,500)
2008	8,487	6,647	1,840	1,340	(1,152)	1,400	(1,100)
2009	8,728	6,754	1,974	1,328	176	1,403	303
2010	9,127	6,369	2,758	1,714	1,890	1,831	2,134
2011	9,414	6,384	3,030	1,740	3,630	1,878	4,012
2012	9,527	6,292	3,235	1,716	5,346	1,873	5,885
2013	8,651	6,074	2,577	1,262	6,608	1,393	7,279
2014	9,127	5,968	3,159	1,430	8,038	1,595	8,874
2015	9,053	5,859	3,194	1,336	9,373	1,507	10,381
2016	8,485	5,262	3,223	1,245	10,618	1,420	11,800
2017	8,082	5,308	2,774	990	11,608	1,141	12,942
2018	8,967	5,366	3,601	1,187	12,794	1,384	14,325
2019	9,954	5,222	4,732	1,441	14,235	1,698	16,024
2020	11,232	5,064	6,168	1,735	15,970	2,068	18,091
2021	11,013	5,117	5,896	1,532	17,502	1,846	19,937
2022	11,159	4,797	6,362	1,527	19,030	1,860	21,797

Q. What are the sources for the revenue requirements figures on Tables 1 through 5?

A. The annual revenue requirements figures presented in Tables 1 through 5 for the years 2005-2022 are taken directly from APS's response to Data Request LCA 8-237. Unfortunately, APS did not include in this response the revenue requirements for the second half of 2004 during which the PWEC units will be in rate base if the Commission approves the Company's request to acquire and ratebase the units.

Therefore, we have used the fixed costs for 2004 for each of the PWEC units that were provided in APS's response to Data Request LCA 7-219.

Q. How did you calculate the annual total market revenues presented in Tables 1 through 5?

A. The total market revenues shown in Tables 1 through 5 are based on the annual amounts of capacity and energy from each PWEC unit multiplied by the respective annual capacity and energy prices.

Q. What estimates of generation have you used for each of the PWEC units?

A. We have used APS's projections of annual generation for each of the PWEC units for the years 2005 through 2022 as presented in its response to Data Request LCA

8-237. Because we did not find any projections of the annual generation that the Company currently expects from each of the PWEC units during 2004, we assumed that each of the PWEC would generate approximately 2/3 as much power during the second half of 2004 as APS's 2003 Long Range Forecast projected the unit would generate in 2005.[3]

In addition, we used the individual unit variable fuel costs ($/MWH) that were provided in APS's response to Data Request LCA 8-237 for the year 2005 because we did not have the comparable information for the year 2004.

Q. What energy market prices have you used in the comparisons shown in Tables 1 through 5?

A. To be conservative we have used the adjusted energy prices for the years 2005 through 2022 that were provided by APS in its response to Data Request LCA 8-237. We assumed that the energy market prices (in $/MWH) for the generation from each PWEC unit would be the same in 2004 as APS has projected for 2005.

Q. What capacity prices have you have used in the comparisons shown in Tables 1 through 5?

A. We used APS's near term capacity price forecasts for the years 2004 and 2005. For the years 2006-2022 we have used the Company's forecast of capacity prices based on the long run marginal costs related to the need to maintain a 15 percent reserve margin in Arizona. APS has explained the derivation of these fundamental capacity prices as follows:

> APS assesses loads and resources of the WECC and each of the sub-regions (WECC Sub-region Supply & Demand Balance was provided in LCA 6-192). Once the plants currently under

---

[3] The information from APS's 2003 Long Range Forecast that was provided in response to Data Request RUCO 10-8 did not include any generation projections for the PWEC units for 2004. However, the Company's 2002 Long Range Forecast projected that the units would generate about as much energy in 2004 as they would in 2005. We then assumed that because the second half of 2004, during which the PWEC units would be in rate base, would include three of the four peak summer months, that each unit would generate about 2/3 of its annual output during the second half of the year. We also tested to make sure that this assumption did not have a major impact on the results.

> construction are completed, a capacity price is added to the energy market price that would be sufficient to incent construction of new generation when the reserve level would drop below 18% in the Desert Southwest sub-region, or 15% in Arizona. When reserve levels are above the 15%, the capacity price is reduced based on a level that supports continued operation of enough existing generation to maintain 15% reserves. The resource plans are developed so that the market is in equilibrium, i.e., it maintains 15% reserve margins once the short term excess goes away. This is represented by the "Fundamental Market Scenario" provided in response to LCA 8-237.[4]

Q. Isn't it reasonable to expect that there would be some physical and economic "lumpiness" when new large generating units are added by APS?[5]

A. Yes. It is reasonable to expect that there might be a few years of lumpiness in which the additional costs of ratebasing a new large generating unit would exceed the benefits of adding the unit. However, as Tables 1 through 5 show, ratebasing the West Phoenix and Redhawk units will not provide any overall cumulative savings for ratepayers until the year 2018 or later. This is far more than mere "lumpiness."

Q. What weight should the Commission give to Company analyses that show that the PWEC units might produce net economic savings over their entire operating lives?

A. Even if APS is able to produce a study which projects that the PWEC units might be expected to produce an overall net life cycle economic benefit despite large losses in the early years, that showing would not justify the plants as economic investments today. The timing and magnitude of the losses expected in the near future would have to be considered as well. It would be unfair to make the Company's current customers pay substantially higher rates during near-term years when there is only a remote possibility that they or future generations of

---

4 APS response to Data Request LCA 19-478(a).

5 Testimony of APS witness Ajit Bhatti, at page 38, lines 1 through 16.

ratepayers will see an overall savings from the units until two decades in the future, if at all.

Q. Has APS examined the economic costs and benefits of the PWEC units using any other market price forecasts?

A. Yes. APS examined a scenario in which the base market capacity price forecast is based on overbuild/underbuild ("boom and bust") cycles and wet/dry hydro cycles.[6]

APS also examined an even more severe underbuilding scenario in which no new generation would be built through 2010. As a result capacity prices spiked to about half of the observed prices in 2001. Beginning in 2011, the market would return to overbuild/underbuild cycles.

Q. Do you believe that it is reasonable to use boom and bust projections of market prices in examining the economic costs and benefits of a proposed capacity acquisition?

A. No. In theory it seems like a good idea to reflect possible boom and bust capacity cycles in the valuation of a proposed capacity acquisition. However, in practice predicting when the boom and bust phases of the cycle will occur, how long each phase will last, how severe each phase will be and what the market prices will be really is far too speculative to produce reliable results. These important factors simply cannot be predicted with any reasonable degree of certainty.

It is far more reasonable to use the more traditional long run marginal costs to evaluate the economic costs and benefits of a proposed capacity acquisition.

---

6 APS response to Data Request LCA 8-237.

Q. Have you seen any evidence that suggests that the next capacity shortage will not occur in 2007 as APS and Dr. Hieronymus hypothesize?[7]

A. Yes. Dr. Hieronymus cites a recent California Energy Commission study as the main support for his conclusion that a new shortage of capacity will reemerge in the Western U.S. by 2007.[8] This study found that although electricity supply resources in California appear to be sufficient for 2004 and 2005, there is an ongoing need to monitor new capacity proposed for the period starting 2006 and beyond. Consequently, the Commission should continue to focus on programs that improve efficiency and reduce demand and to support policies that ensure that new generation is brought to the market.[9]

In his testimony, Dr. Hieronymus cites several factors which he believes will make the capacity situation in California worse than it appears in this recent Energy Commission study. However, he ignores a number of factors which actually make the situation in California far less dire than he would suggest.

First, the California Energy Commission study assumes that only one third of the voluntary conservation achieved in the State during the 2001 electricity crisis will persist in 2003 and that this amount will decline in subsequent years. This is an extremely conservative assumption. It is very reasonable to assume that Californians who conserved energy during the 2001 crisis would again conserve if faced with the prospect of another capacity shortage in 2007 or any subsequent year(s). Such conservation efforts could reduce future electricity demands by 2,700 MW or more over the figures shown in the 2003 California Energy Commission study.

Second, the study notes that California will have about 1,100 MW of Emergency Demand Programs/Interruptible loads that will further add to the State's reserves

---

7 Testimony of William H. Hieronymus, at page 59, lines 5 through 7.

8 Testimony of William H. Hieronymus, at pages 62 and 63.

9 *California's 2003 Electricity Supply and Demand Balance and Five-Year Outlook*, available at the California Energy Commission website, www.energy.ca.gov.

in 2007 and subsequent years. The California Public Utilities Commission has established a goal of increasing the amount of demand response in the State to over 1,900 MW by 2007.

Third, the California Energy Commission study assumes dry hydro conditions which it says has a one in five year probability of occurring. This assumption reduces the amounts of power imports available from the Pacific Northwest and from the spot market.

Finally, the California Energy Commission study only includes those power plants deemed as having a 75 percent or greater probability of coming on-line. This essentially means that the study only assumes that the approximately 4,000 MW of power plants that are currently under construction will be built. It does not assume that any of the additional 4,000 MW of approved plants that are currently on hold will be built or that any of the 6,000 MW of plants that are currently undergoing Energy Commission review will be built. This is an extremely conservative assumption especially if the developers of these projects agree with Dr. Hieronymus's conjecture that a new capacity shortage, with significantly higher prices, will reemerge by 2007. Clearly, the prospect of much higher capacity prices in the California market and the rest of the Western U.S. in 2007 will encourage more developers to complete their projects as expeditiously as possible.

Q. Do you think that the more severe underbuilding scenario examined by APS is more reasonable than the boom/bust cycles scenario?

A. No. The severe underbuilding scenario examined by APS is simply not credible. Given the very large number of new facilities that are undergoing review in the Western States and the amount of plants that have been announced, it is not reasonable to expect that no additional generation will be added until 2011 once the plants currently under construction are completed.

If APS wanted to examine a severe underbuilding scenario, it should also have looked at a scenario in which there is a more extreme overbuilding of new generation facilities in the short term leading to a capacity glut that will last further into the future than APS conjectures in its boom and bust cycles scenario.

Q. Have you seen any evidence that suggests that any party would be interested in selling a generating unit or in making a long-term capacity sale to APS?

A. Yes. [

][10]

In addition, APS has acknowledged that it is involved in several confidential discussions concerning potential power plant purchases:

> One way to secure long-term supplies in an otherwise dysfunctional market and to avoid the problem of potentially insolvent sellers, is to build or buy power plants. APS has questions about its ability to pursue these options but it is exploring them in any event. Thus, APS entertained representatives from Dome Valley Energy Partner LLC on October 8, 2003 to discuss the overall status of the Wellton Mohawk Generating Facility. No specific detailed and/or substantive discussions involving a firm offer for energy occurred as a result of this meeting. In addition, APS approached and has had brief discussions with two non-affiliated entities concerning the possible purchase of their generating facilities in Arizona. APS is bound by confidentiality agreements with regard to such discussions, which have led to no further communications with these entities. Finally, APS has approached and is currently in confidential discussions with one (non-affiliated) entity concerning that entity's desire to sell a generating facility in Arizona. Those discussions, all analyses in conjunction with those discussions, and even the identify of the potential seller are covered by a confidentiality agreement with such seller.[11]

Q. Have any power plants in Arizona recently been sold?

A. Yes. Reliant Energy recently sold the 590 MW Denver Basin plant to SRP for $288.5 million, or about $492 per KW.

---

10 [ ]

11 APS Response to Data Request LCA 10-269.

Q. Have you seen any evidence that suggests that the PWEC units were not built "primarily" to serve APS load, as APS witness Bhatti has claimed?[12]

Yes. Numerous APS and PWEC planning studies indicated that the PWEC units were being built to facilitate power sales to areas outside Arizona. For example:

- APS's "1998 Business Plan – Generation Growth Plan" noted that the "Primary Market Targets" for PWEC generation would be "Phoenix, Yuma, Gila Bend, Saguaro, Cholla, Prescott, S Nevada, California, Northwest, New Mexico, Utah & Colorado."[13]
- [ ][14] Project Hedgehog became the Redhawk units.
- [ ][15]
- A 1999 APS "Planning Scenarios Risk Assessment" revealed that PWEC was planning to add significantly more generation than would be needed just to serve APS loads. For example, PWEC expected to have approximately 8,900 MW of capacity by 2006, significantly above APS's projected load which was in the range of 6,300 MW.[16]
- The Company's September 29, 1999 Pinnacle West Press Release announcing the proposed Redhawk units noted that "The plant will compete in deregulated energy markets of Arizona, California and other western states…"[17] The press release also quoted Pinnacle West Generation Business Unit President William Stewart as stating that "We intend to be a vigorous player in these competitive generation markets. We have a strong record of low-cost, efficient plant operation. We can best serve the public and our shareholders by pursuing these developing markets, particularly in Arizona and the Southwest."

---

12 Testimony of Ajit Bhatti, at page 17, line 19, to page 18, line 2.

13 Provided in APS's response to Data Request LCA 11-288, at page 15 of 44.

14 [ ]

15 [ ]

16 Provided in APS's response to Data Request LCA 6-200B, at page 28.

17 Provided in APS's response to Data Request LCA 3-77.

> The same press release also noted that the site for the proposed Redhawk units "was selected because the Palo Verde switchyard is a major transmission hub and provides access to energy markets in Arizona, California and across the Southwest."

This is not to say that Pinnacle West intended to abandon APS's traditional service territory in Arizona. Company management was astute enough to realize that the Phoenix area was one of the fastest growing areas in the West and could provide a strong foundation from which Pinnacle West could compete in other Western region markets.

[ ] For example:

- [ ][18]
- [ ][19]

  [ ]
- [ ][20]

---

[18] [ ]

[19] [ ]

[20] [ ]

- [ ][21]
- [ ]

Q. Do you have any comment on the claim by APS witness Bhatti that the location of the PWEC units demonstrates that they were built at locations where they were needed to serve APS load and with APS customers in mind?[23]

A. Yes. Mr. Bhatti implies that siting the Redhawk and the West Phoenix units in locations where they could serve APS load was somehow inconsistent or in conflict with siting those units at locations from which they could serve other markets. As I noted earlier, the September 29, 1999 Press Release in which APS announced the Redhawk Project specifically noted that the site for the proposed plant "was selected because the Palo Verde switchyard is a major transmission hub and provides access to energy markets in Arizona, California and across the Southwest."

At the same time, while the West Phoenix units were built in the Phoenix Valley, their power could be exported out of the Phoenix load pocket to Palo Verde. The use of the capacity from the new West Phoenix Units 4 and 5 to serve in-Valley loads also would free up other PWEC generation located outside the load pocket to be sold in other markets.

---

21 [ ]

22 [ ]

23 Testimony of Ajit Bhatti, at page 5, lines 8-10, and page 18, lines 5-7.

Q. APS witness Bhatti makes a number of claims regarding the decision by Pinnacle West management not to sell power from the PWEC units forward to California.[24] Have you seen any evidence that PWEC was not interested in selling power into the California market?

A. No. Mr. Bhatti has implied that Pinnacle West declined from selling power in California in order to be able to serve APS loads. However, as I have noted above, there is no evidence that PWEC has ever abandoned its interest in selling power into the California markets.

Q. Does it appear that in order to improve its ability to sell power into the regional markets PWEC built a different resource mix with more baseload combined cycle capacity (and less peaking capacity) than would have been needed just to serve the growing APS loads?

A. Yes. By the 1990s APS was a company with a generation capacity mix that was more than 70 percent baseload.[25] This was a baseload heavy capacity mix, especially for a Company that traditionally has had a fairly low load factor, i.e., less than 55 percent, due to the extreme summer temperatures and the relative lack of a substantial industrial process baseload.

Given this low load factor, it appears reasonable to expect that if it had been building to meet its own needs, APS, as a regulated company, would have added a significant amount of peaking capacity as part of its generation growth plan. In fact, APS's June 1998 Generation Growth Plan did specifically note that "If construction based on Arizona growth plan only, it would install new CT capacity beginning in 2004 and new combined cycle capacity, or previously installed CTs upgraded, starting in 2006.[26]

---

[24] For example, see the Testimony of Ajit Bhatti, at page 18, lines 5-7, page 18, lines 16-19, and page 49, lines 20-22.

[25] For example, see the [

].

[26] Provided as document RC01608 in APS's response to Data Request LCA 11-288, at page 6.

However, as a fledgling merchant generator, PWEC's interest was in developing new baseload generation that could compete in other out-of-state markets even if that baseload generation had higher installation costs than the CT capacity that APS would need to serve its growing summer peak loads. Consequently, PWEC developed a generation growth plan that included four new combined cycle units as its first four major new additions (West Phoenix Unit 4, West Phoenix Unit 5, and Redhawk Units 1 and 2). The new Saguaro unit is the only CT that PWEC has added. Thus, approximately, 1,600 MW of the 1,700 MW, or about 94 percent, of the new capacity that APS is seeking to acquire from PWEC is baseload combined cycle capacity. This is far too much for a company that already has a generation mix that is 70 percent baseload. In fact, with the PWEC units, APS's generation would be more than 75 percent baseload.

Q. Has the Company acknowledged that adding more single cycle turbine capacity would be a better mix with APS's needs?

A. [

][27]

Q. Have you seen any other evidence that suggests that single cycle turbine peaking capacity would have been a better match for APS's needs than the combined cycle capacity built by PWEC?

A. Yes. The limited number of hours that APS needs RMR capacity in the Phoenix load pocket and the relatively low capacity factors that APS currently projects for West Phoenix Unit 4 through 2022 suggest that some of the new capacity that APS needs should be single cycle turbines peaking units instead of baseload combined cycle. This information is presented in Tables 6 and 7 below:

---

[27] [ ]

Table 6: Phoenix Area Non-APS RMR Requirements for APS Load[28]

Year	Non-APS RMR Hours
2003	152
2004	200
2005	230

Table 7: Projected West Phoenix and Redhawk Capacity Factors[29]

Year	West Phoenix Unit 4	West Phoenix Unit 5	Redhawk
2005	15.1%	39.1%	27.4%
2006	18.6%	45.0%	39.3%
2007	18.6%	44.8%	39.9%
2008	25.3%	40.4%	52.0%
2009	22.8%	50.8%	49.2%
2010	25.5%	51.2%	46.0%
2011	23.0%	49.0%	42.6%
2012	27.3%	50.3%	47.7%
2013	27.5%	55.9%	46.7%
2014	33.1%	49.9%	51.1%
2015	28.6%	53.3%	51.2%
2016	33.8%	54.5%	53.3%
2017	40.2%	56.1%	55.9%
2018	31.7%	55.1%	54.6%
2019	25.7%	54.3%	53.4%
2020	20.7%	53.4%	52.1%
2021	21.4%	57.9%	51.2%
2022	23.0%	55.1%	52.1%

These projected capacity factors also suggest that some of the Redhawk capacity should have been single cycle turbines, at least initially.

28 *APS Reliability Must-Run Analysis 2003-2005*, Table ES3, at page 8, and Table 6A, at page 28.

29 Source: APS response to Data Request LCA 8-237.

Q. Do you have any comments on the claim by APS witness Bhatti that ratebasing the PWEC units could have been anticipated to yield benefits ranging from approximately $496 million to $615 million in net present value over the life of the projects.[30]

A. Yes. Mr. Bhatti's retrospective analyses do not provide any insights into the critical question of whether acquiring the PWEC units is the most economic option available to APS at this time. APS did not actually conduct these comparisons during the years 1999 through 2002 and did not acquire the PWEC units during that timeframe. Therefore, Mr. Bhatti's comparisons have no relevance to the current proceeding.

Moreover, many of the studies upon which Mr. Bhatti bases his retrospective comparisons assumed very high capacity factors for the West Phoenix and Redhawk units.[31] This was overly optimistic given the significant number of new combined cycle units that were being proposed for Arizona and the rest of the Western region during the 1999-2002 timeframe. The use of these high capacity factors biased the results of Mr. Bhatti's comparisons in favor of the ratebasing of the PWEC units because it increased the market revenues against which the revenue requirements from ratebasing were being compared.

[

]

---

30 Testimony of Ajit Bhatti, at page 68, lines 1-10.

31 [

]

[

]

Q. Is there currently any capacity crisis requiring that the Commission act at this time to allow APS to acquire the PWEC units and to include them in rate base?

A. No. APS has an existing contract with PWEC for capacity from the units during the months of June, July, August and September through 2006. To the extent that APS needs additional capacity during other, non-summer peak periods, it should be able to acquire that capacity at low prices from PWEC or other sellers. After all, APS's own witness in this Docket, Dr. Hieronymus, has testified that "Near term prices are forecast to be relatively low, reflecting the glut of capacity coming on-line in the western U.S. in 2002-2003 …."[32] and has noted the "price-depressing effect" of this glut of new capacity.[33]

Q. Have you reviewed APS's January 27, 2003 Summary of Responses Received to its Power Supply Request for Proposals?

A. Yes. APS provided the Summary to RUCO which forwarded it to me.

Q. In your opinion, will the information provided by APS in this Summary enable the Commission to determine whether the PWEC units represent the most economic capacity that APS could acquire at this time?

A. No. The information provided by APS about the bids it has received is far too cursory to enable the Commission to evaluate whether the PWEC units represent the most economic capacity that it could acquire in the market. APS has provided no information on the prices and durations of the individual bids. Nor has APS indicated the gas price forecast it has used to develop the range of levelized costs presented in the Summary. This information is essential in order to compare the

---

32 Testimony of William H. Hieronymus, at page 51, line 23, to page 52, line 1.

33 Testimony of William H. Hieronymus, at page 59, lines 9-13.

economic savings and costs from acquiring the PWEC units against the capacity options bid in response to APS's Request for Proposals.

Moreover, PWEC did not submit a bid. Therefore, it is not possible to evaluate what value PWEC places on the capacity it is seeking to sell to APS.

Q. Is it reasonable to expect that APS could provide information on the individual bids without compromising the bidding process or seriously prejudicing the negotiation process that may occur as part of the RFP?

A. Yes. APS could provide the information pursuant to the confidentiality agreements that RUCO and other parties have signed in this proceeding. APS also could white out the names of the individual bidders and the facility-specific information that might reveal the identities of the individual bidders. The possibility that information provided by bidders might be revealed to third parties, if required by the Commission, was clearly contemplated in Section XI, "Confidentiality," of the December 3, 2003 Power Supply Request for Proposals.

Q. APS's January 27, 2004 Summary notes that none of the PPA proposals involved a fixed-price bid and that all of the proposals would require APS and its customers to bear and/or assume the risk related to natural gas prices and/or transportation. Would this be any different than the risks that ratepayers would bear if the PWEC units are acquired by APS and placed into rate base?

A. No. For example, I have seen no evidence that if APS acquires the PWEC units and places them into rate base, it will commit to provide the power from those facilities at fixed prices. Instead, the Company's customers will bear the risks associated with natural gas prices. Similarly, I have seen no evidence that APS would refrain from seeking future rate increases to reflect higher than currently projected plant operations & maintenance expenses.

Q. What is your recommendation to the Commission regarding APS's request to acquire and ratebase the five PWEC units?

A. The Commission should deny APS's request to acquire and rate base the PWEC units. Instead of allowing APS to add the PWEC units, the Commission should require that APS immediately undertake the development of a least-cost plan that includes a portfolio of demand-side, generation and transmission options. As part of this plan, APS should be required to undertake a competitive bidding process for power supply contracts (short, medium and long-term) and the purchase of part of all of existing generation facilities. This plan should be developed in order to be in place immediately following after the end of the Track B contracts in 2006 or sooner, if possible. PWEC could bid in this competitive process.

Q. Is it possible that the results of this power supply solicitation could be used to help develop this least-cost plan?

A. Yes. It is possible that the bids received by APS in response to its December 3, 2003 Power Supply Request for Proposals could be helpful in developing such a least-cost plan. However, PWEC did not submit any bid(s) in response to the latest Power Supply Request for Proposals. Moreover, it does not appear that any of the bids were for short-term or medium-term power supply agreements. Therefore, an additional competitive bidding solicitation may be necessary.

Q. Is it possible that merchant generators could supply power to APS in the Phoenix load pocket in place of the PWEC units?

A. Yes. The addition of planned transmission facilities can be expected to increase the ability of merchant generators to send power into the Phoenix load pocket.

For example, Figure 7.5 in the ACC's Second Biennial Transmission Assessment 2002-2011 shows that the import transmission capacity into the Phoenix Valley will increase substantially by 2008 – by more than 1,200 MW. This would enhance the ability of generators outside the Valley to serve loads inside the Valley during what would otherwise be RMR hours.

Consequently, as is shown in Figure 7.4 in the ACC's Second Biennial Transmission Assessment 2002-2011 shows that during the years 2004-2010 there will be substantially more in-Valley generation and transmission capability than will be needed to serve the combined Valley peak loads.

An APS Valley Import Analysis presented in the Rebuttal Testimony of APS witness Cary Deise in Docket No. E-01345A-01-0822 similarly showed that the addition of the planned Palo Verde – Table Mesa 500 kV transmission line in 2008 would significantly reduce APS's Valley Local Generation Requirements.

In addition, new transmission system enhancements may be developed as a result of the Arizona collaborative transmission planning process, in general, and the Central Arizona Transmission planning analyses, in particular.

Q. **Are you prepared to address the questions raised by Commissioner Gleason in his letter of September 5, 2003?**

A. Yes.

Commissioner Gleason Question No. 1 – How should the Commission calculate the market value of a power plant?

Answer – With a deregulated wholesale market, the Commission should determine the value of a power plant through a competitive power solicitation.

Commissioner Gleason Question No. 2 – If the Commission should look at the plant's current market value instead of the original cost to build the plant, how can the Commission determine the market value?

Answer - The value of a power plant will be determined by the price at which the plant is bid if the plant is the winning bid.

Commissioner Gleason Question No. 3 – What power plants are on the market that can serve Arizona consumers?

Answer – [

][34]

In addition, APS has acknowledged that it is involved in several confidential discussions concerning potential power plant purchases.

Commissioner Gleason Question No. 4 – Has any other state commission faced a situation where a regulated energy utility applied to incorporate merchant assets into its rate base? What did the commission decide?

Yes. I am aware of two state regulatory commissions which have addressed the situation where a regulated energy utility applied to incorporate merchant assets into its rate base.

The Indiana Utility Regulatory Commission, ("IURC") in December 2002 approved a request by PSI Energy , Inc., for approval to purchase two generating facilities from a merchant affiliate.[35] The IURC's reasoning in approval this application is valuable to this proceeding.

First, the IURC relied heavily on the fact that the utility's resource mix was very heavily weighted towards coal-fired baseload capacity with baseload making up 65 percent of the PSI generation. The IURC specifically found that "PSI's current generating resources are heavily weighted toward baseload capacity while, optimally, the PSI system should be comprised of relatively more peaking capacity." The two units which PSI was seeking approval to acquire from the affiliate were both gas-fired combustion turbine peaking facilities.

Second, the utility, PSI, had conducted a detailed integrated resource planning process, involving the review of more than 4200 alternative resource plans, which identified that acquiring the two peaking facilities was the number one "least cost" plan. As I have noted earlier, APS has presented no evidence in this

---

34 [ ]

35 Indiana Utility Regulatory Commission, Order in Cause No. 42145, 2002 Ind. PUC LEXIS 544, December 19, 2002.

proceeding that acquiring the PWEC units is the least cost alternative for the Company.

In July 2002, the Public Service Commission of the State of Missouri approved a settlement between the AmerenUE Company, the Staff of the Commission and other parties that, in part, allowed AmerenUE to acquire two combustion turbine peaking generating units from an affiliated company, AEG.[36] Other terms of the settlement approved by the Missouri Commission required the utility to reduce its rates by $110 million over three years and to provide a one-time credit of $40 million to its customers. Unfortunately, the Commission's Order does not address the merits of the request to acquire the two generating facilities from the affiliate except to find that the agreement was in the public interest.

The Federal Energy Regulatory Commission ("FERC") subsequently addressed and approved this same transaction.[37] In May, 2003, FERC set a hearing on the request to transfer the generating units in order "to be certain that the purchase of the Pinckneyville and Kinmundy plants at net book value is consistent with results that would be obtained through a competitive process reflecting the interplay between AmerenUE and independent sellers and has not resulted in under preference being shown to AmerenUE's affiliate, AEG."

In the present case, APS has provided no evidence at all to show that the acquisition of the PWEC units is consistent with any results that would be obtained through a competitive process reflecting the interplay between APS and independent sellers. Moreover, there has been a clear preference shown to APS's affiliate, PWEC. In fact, APS has admitted that there weren't even any negotiations between APS and PWEC.[38]

---

36 Public Service Commission of the State of Missouri, Case No. EC-2002-1, 2002 Mo. PSC LEXIS 1036, July 25, 2002.

37 Federal Energy Regulatory Commission, Order Setting Disposition of Facilities Application for Hearing, Docket No. EC03-53-000, 103 F.E.R.C. P61, 128, 2003 FERC LEXIS 819. May 5, 2003.

38 APS's response to Data Request LCA 4-94(b).

The Illinois Commerce Commission ("ICC") also needed to approve the acquisition of the power plants by AmerenUE. The Staff of the ICC filed testimony opposing the acquisition. However, the matter was never resolved as AmerenUE withdrew its application for approval of the asset transfer.[39] Apparently, AmerenUE has decided not to pursue the acquisition of the two generating units.

Q. Does this complete your testimony at this time?

A. Yes.

---

[39] Illinois Commerce Commission, Docket o. 03-0083, 2003 Ill. PUC LEXIS 632, July 23, 2003.

EXHIBIT DAS-1

David A. Schlissel

Senior Consultant
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
(617) 661-3248 ext. 24 • Fax: (617) 661-0599
www.synapse-energy.com
dschlissel@synapse-energy.com

SUMMARY

I have worked for thirty years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric System Reliability - Evaluated whether new transmission lines and generation facilities were needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Analyzed power plant operating data from the NERC Generating Availability Data System (GADS). Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO_2 and CO_2. Examined whether new state emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proosed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Nuclear Power - Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates and cost collection plans. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Electric Industry Regulation and Markets - Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Evaluated the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets. Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and the auctions of power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Evaluated whether new electric generating facilities are used and useful. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than ninety proceedings before regulatory boards and commissions in twenty three states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003

The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115209) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003

Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due tot he fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)